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Investment Case
Tullow Oil Plc.

Master Thesis June 2012

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TULLOW OIL PLC - Executive Summary Oil&Gas	E&P	30 April 2012

Soon To Become a Major International E&P Player

Independent E&P player: Tullow is one of the largest independent E&P companies in the world, with 93% of its assets located in Africa. In March 2012, they announced that the Asian assets are to be sold, which supports their overall strategy to focus on the African region. With a P50 reserve base of 1.139 mmboe and many potential exploration prospects, they are still in the beginning of the E&P cycle.

Self funding E&P company: The cash flow from producing assets and a credit facility finance the exploration activity, and this enables Tullow to have a well operating self-funding business model. Their need of a credit facility will diminish in 2015 transforming Tullow into a complete self funding E&P company.

Increasing production: They intend to more than double their production the next five years, and the largest contributors to this growth will be Ghana and Uganda. West Africa and the South American assets are possible long-term catalysts for further production growth and the share-price.

Farm-down approval in Uganda: In March 2012, the Ugandan government approved the farm-down of the assets in Lake Albert to CNOOC and Total, for a consideration of $2,9bn. This enabled the partners to commence the development, and first commercial production is planned in 2015. Tullow´s financial position has never been better due to the farm-down.

12-month target price: Tullow has an experienced management, with a good track record within the operations and M&A history. Tullow´s equity value is estimated to 1.865 pence, a 5% premium to NAV with a possible upside of 22% from today´s share price of 1.534 pence.

Price (GBp)	1.534
NAV Value (GBp)	1.776
Potential TP upside	22%
Consensus TP (GBp)	1.584
12-month Target Price	**1.865**
12-month rating	**BUY**

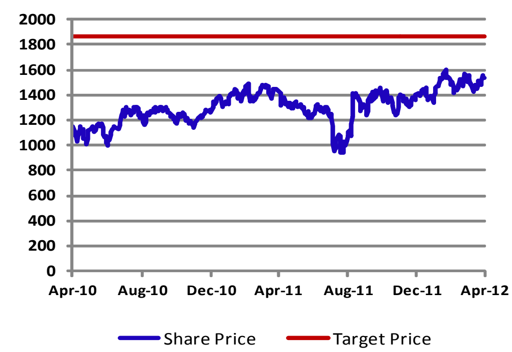
Trading Data	
Ticker Bloomberg	TLW LN Equity
Market cap. (mGBP)	13.906
Shares Outstanding (m)	905
Free float	100%
EV (mGBP)	13.742
52 week range (GBp)	946 - 1.601

Assumptions	
LT Oil Price (USD/bbl)	95
LT Gas Price (GBp/therm)	55
WACC	8,86%

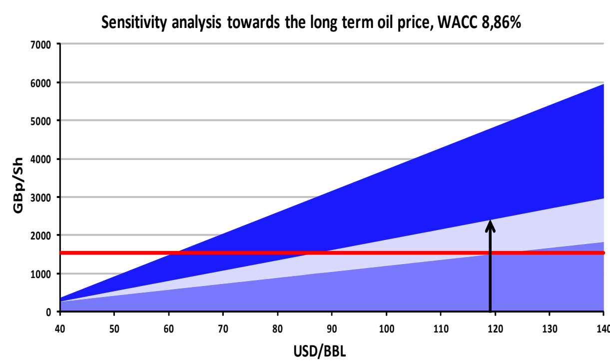
Key multiples	2011A	2012E	2013E	2014E
DACF	1.731	1.242	1.839	1.982
FCFE	91	-711	-344	-563
ROIC	8,4%	8,0%	8,8%	7,4%
ROACE	8,5%	6,5%	7,7%	6,5%
EV/BOE 2P	9,9x	12,1x	12,1x	12,1x
P/B	3,7x	3,0x	2,5x	2,3x
P / E (dil)	1,9x	6,2x	71,7x	14,6x
EV / EBITDA	37,8x	18,2x	7,7x	7,5x
EV / NOPLAT	246,8x	86,3x	17,9x	20,1x
Divid. Yield	0,4%	0,4%	0,8%	0,9%
KBOEPD	78	77	100	128

FINANCIAL DATA (m$)	2009A	2010A	2011A	2012E	2013E	2014E	11-'14 CAGR
Net sales	582	1.090	2.304	2.356	2.868	3.126	11%
EBITDA	363	756	1.784	1.829	2.275	2.424	11%
EBIT	82	234	1.130	1.140	1.426	1.376	7%
EBT	20	152	1.073	2.112	1.322	1.282	6%
Net income	19	73	689	1.187	705	673	-1%
EPS GBp/sh	2	4	45	9	45	43	-1%
Cash	158	338	307	-	-	-	-100%
Long Term Assets	4.274	6.977	9.423	8.762	10.016	11.442	7%
Debt	817	2.200	3.076	766	1.316	2.083	-12%
Shareholders' equity	3.045	3.808	4.690	5.631	6.089	6.515	12%
Net debt	667	1.862	2.769	766	1.316	2.083	-9%
CF from operations	144	738	1.745	1.222	1.758	1.912	3%
CF from investing	-746	-2.797	-2.055	1.080	-2.102	-2.475	6%
CF from financing	489	2.149	304	-3.219	-205	-204	-188%

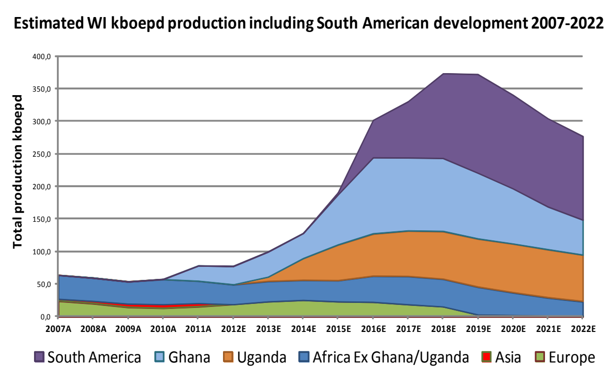
Performance and Target Price



GRAPHS: SENSITIVITY TOWARDS OIL PRICE AND EXPECTED PRODUCTION DEVELOPMENT



Source: Own calculations, NAV model



Source: Own calculations, NAV Model

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Master Thesis preface

Before presenting the final report, there are some matters we want to clarify and some presumptions we wish to emphasize.

Motivation: We are both graduates in Finance, and when choosing which field to write our master thesis within, a valuation of a company was a natural choice. As we both previously have worked in and closely with financial institutions, we understand their need to maintain a high level of integrity through investment recommendations on solid in-depth strategic analyses and carefully conducted valuation proposals. This thesis is written as an investment case, and will function as a solid base of information to be used for decision-making, investment recommendation and further analysis for a financial institution.

Through previous work with investment decisions regarding energy companies, we have found the oil industry to be the most interesting one. It consists of several interesting sub sectors, from oil service companies to Integrated Oil Companies (IOC's) and Exploration and Production (E&P) companies. The E&P sector is interesting due to their high correlation with the oil price combined with the need for a competent management, and a good strategy to identify and acquire the best assets available. It is also different from all other sectors due to its high volatility, and hereby high potential upside. One of the authors has also worked with the E&P sector for two years in the Danish asset management company BankInvest, and this experience combined with the information accessible through work connections, support our eagerness to further analyse the industry.

The sector is homogeneous, and the companies need to differentiate through areas of operation, management, financing, assets with different risks and "know how". In a time where the world´s oil reservoirs are shrinking, the best E&P companies may outperform the market due to these micro factors that affect them. A company that has managed this is Tullow Plc. They have vastly outperformed the market the last decade through thorough analysis of prospective fields and allocation of funds to the projects with the highest investor return. It is also one of the world's largest independent E&P company, and it is built step by step through two decades to enable a sustainable growth. Valuing Tullow is therefore both an interesting and challenging task as they have proven to be able to differentiate themselves in several areas, and must continue to do this in the future to maintain their current momentum.

Problem statement: Throughout the period, we have held a close dialog with Head of Equities in BankInvest, Kasper Elmgreen. He has guided us in which factors that are the most important to assess when conducting a valuation of an E&P company, and together we have decided upon a problem statement that represents the foundation of the report. The specific problem reflects what we see as the main interest for potential investors, and has helped us to keep focus on the topics our report should cover.

The problem statement and sub-problems are expressed as follows:

- What is the fair value of Tullow's Equity?
    - How is the asset base built, and how has it evolved over the recent years?
    - What are Tullow's competitive advantages?
    - What catalysts can affect Tullow in the upcoming years?

Model: To find the fair value of Tullow, we have chosen to build a Net Asset Value (NAV) model. This is a model that is built on the asset level, and not on a corporate level like a in a Discounted Cash Flow (DCF) model. The company's assets are first valued separately, before they are all incorporated in the NAV model, to find a combined value. A thorough discussion of why a NAV model is chosen rather than a DCF model can be found in part 6 - The thesis in perspective. In addition, the model is enclosed in appendix 15 – 45.

Structure: The structure of the thesis is developed in the way we think creates the best reading flow. The first part gives an introduction to the oil industry, before the company is described, and its main characteristics are pointed out. The second part presents some strategic factors that are important to Tullow in their operations, before a detailed description of the asset base is given. In the third part, the different input factors and assumptions used in the NAV model are described, both at a general level and for the specific countries included. The final part of the thesis analyses the NAV model, and concludes with presenting a fair value of the company.

Practical information: There is some practical information that needs to be presented before proceeding to section 1 of the report. First, we have decided on a cut-off date (April 30. 2012) for Tullow' share price. We have not included information published after this date in our analysis. At this point, the Tullow share traded on the London Stock Exchange at GBp 1.534. Secondly, for those who are not very familiar with the Oil industry, appendix 2 presents a short introduction to measurements and key concepts used within the industry.

Finally, we do not use a fixed currency exchange rate in our calculations, but utilize historical and forward currency exchange rates from Bloomberg.

Throughout the process, creating value for potential investors has been the most important determinant in our approach to value Tullow Plc. We have included an introduction to the oil industry to clarify different terms and give a general understanding of the E&P sector. The interested reader can find more details on specific issues in appendixes, which are referred to throughout the text where relevant. Some of the arguments and knowledge concerning Tullow and the oil industry are based on conference calls with analysts and E&P companies, analyst meetings and other work related activities. This information is given references when possible. Further, a complete reference guide is included after our conclusion[1]. The reference guide is structured alphabetically based on the publisher of the report, articles, books etc. Throughout the report we list footnotes references and the reader can find more information in the reference guide. In addition, an overview of the different figures and tables can be found in appendix 1.

1 Some of the sources we have listed were provided to us directly by contacts in financial institutions and will not be available directly on the Internet, as they are not public. If any of these documents are requested, we might be able to supply them if confidentiality issues are not present

1 Tullow

1.1 Branch Description

The oil industry is one of the largest business sectors in the world. It provides a good that is in demand all over the world both from the single consumers to the industrial sector. The business is roughly divided into Integrated Oil Companies (IOC), oil service companies and E&P companies. IOCs are large cooperation's operating both within upstream (E&P) and downstream (to the consumer) such as Statoil and Shell. Oil service companies are those who provide different operating equipment and knowledge within drilling of wells, seismic shooting, accommodation rigs, subsea installations, and so on.

The E&P sector is capital intensive with a high level of capital expenditures (capex). A solid balance sheet for a company early in the PLC[2] is important because of the uncertainties regarding future cash flow. Most E&P companies´ balance sheet is therefore dominated by equity capital that also increases the risk-return demand. Parallel to this, it is important to acquire new assets for potential growth. The role of the management is therefore very important.

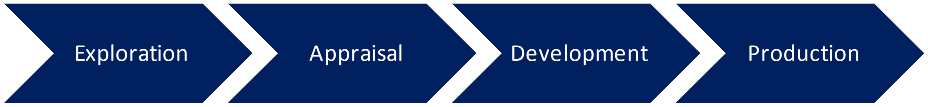
1.1.1.1 Oil and Gas Reservoir Definitions

There are many definitions concerning oil reservoirs, volume of oil and classifications of oil. Volume definitions and glossary of commonly used terms can be seen in appendix 2, and the classification of different oil types is presented in part 1.1.3.5. Looking at the reservoir levels, these can be divided into two sub-categories, Commercial and Contingent reserves. Commercial reserves are the reserves in production and contingent reserves are the prospects where oil have been discovered, but further development has not yet begun.

In addition to this, the reserves are divided into probability classes, namely 10P, 50P and 90P. P50 levels describe that it is 50% probability that the reservoir levels are X or higher than X. Similar with the 10P and 90P, though with the respective probabilities. Throughout the valuation, the P50 values are most commonly used in million barrels of oil equivalents (mmboe), and the same for P10 values, which describes the upside potential. These values are often combined with the expressions commercial and contingent, as explained above. For further explanation, see part 3.2 – Output description.

2 This is elaborated in part 1.1.3.6 – Typical life cycle of an oil field

1.1.2 E&P



1.1.2.1 Exploration

Exploration (E) means to detect and determine the extent of oil and gas in potential structures, in other words; to search for oil and gas. The first step in an exploration process is to conduct a gravity survey, a magnetic survey, and a regional seismic reflection in areas thought to contain hydrocarbons. If large scale features of sub-surface geology are detected, more detailed seismic surveys are conducted in certain areas to get an even better picture of the sub-surface structure. Then, if the prognoses of the presence of hydrocarbons are positive for an area, an exploration well is drilled to determine whether it contains oil or gas.

Day rates for seismic surveys and drilling units often amount to several hundred thousand dollars, depending on the specific vessel/rig. Exploration is therefore an expensive and risky operation with a high probability of not finding anything, or reserves that are too small to be commercially profitable[3]. In addition, the exploration activity is highly affected by the oil price, with a long-term correlation of 1[4]. The recent years` high volatility in the oil price has imposed a higher uncertainty in terms of future exploration activity.

1.1.2.2 Appraisal

The appraisal (A) phase is the analysis of the previous exploration drilling, and appraisal wells are drilled after hydrocarbons have been discovered to appraise its content and to determine the optimum platform location[5]. In addition to drilling additional wells, it involves gathering more seismic data to further reduce uncertainty about the size and quality of the field[6].

1.1.2.3 Development

The development (D) phase is the planning of the oil production and how the fields should be operated. A company might build a pipeline to secure levelled production, which can take years to build. As of this, the development phase might be characterized as a

3 The global industry historic exploration success rate was 38% over the last 10 years (see part 2.1.3 – Exploration success rate).

4 Deutsche Bank – Oil and gas for beginners (2010) *p.56*

5 Deutsche Bank – Oil and gas for beginners (2010) *p.443*

6 Deutsche Bank – Oil and gas for beginners (2010) *p.69*

coordination of infrastructure where the goal is to optimize the planned production, but also to create real-options for tie-backs[7] to nearby projects. Thus, the crucial factor in this phase is finding the most cost- and time efficient type of production activity, which ensures that the project will be completed within budget and on schedule. In addition, the development phase explores the different production possibilities. Should it be a subsea installation with FPSO or a production platform? Also, are there any new technologies that can be suited for this oil field that can increase the extraction rate? These questions are of high importance in the development phase.

The company may also proceed with a farm-down, where they sell a certain stake of the oil field to cooperating companies, often as strategic partnerships where ones weakness might be another one´s strength. If a pipeline is to be built, cooperation with an oil company that has history of building pipelines might be attractive[8].

1.1.2.4 Production

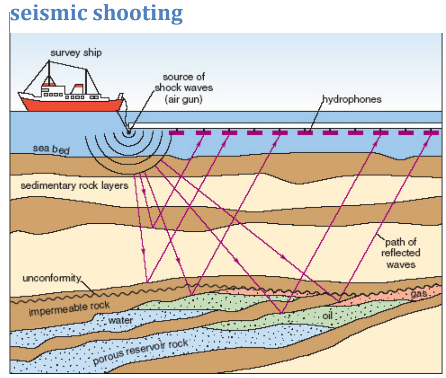
The final phase is the production (P), which is measured in barrels of oil equivalents/oil per day (boepd/bopd). The production increases as the company drills more producing wells in the same field, until it reaches its steady state – where maximum volume is extracted per day[9]. An important value creating activity in this stage is maximizing the economic lifetime of the reserves by drilling infill wells that pumps water or gas into the reservoirs to maintain the pressure.

1.1.3 Oil Service

1.1.3.1 Seismic

Seismic shooting is divided into two distinct processes, acquisition of data and processing of data sets acquired. Vessels with streamers carry out the acquisition of data offshore. The seismic vessels tow an airgun generating sound waves by "shooting" compressed air into the water, before the reflection of the sound waves are detected by a large number of hydrophones attached to streamers trailed behind the

Figure 1.1 Graphical illustration of seismic shooting



7 Connection between new oil and gas discoveries and an existing production set up

8 Deutsche Bank – Oil and gas for beginners (2010) *p.48*

9 See part 3.3.2.1 – Figure 3.11 Typical Production Profile for Oil and Gas.

boat. With several streamers, it is possible to create a 3D picture of the subsurface (commonly 6-8 streamer, but it is possible with as many as 20).

The processing of the data acquired relies on massive computer power, specialized proprietary algorithms, and highly skilled staff at processing centres. The seismic companies often design the survey to its own data processing capabilities (its own proprietary algorithms), before selling the data and interpretation as Multi Client sale[10].

1.1.3.2 Drilling

Oil and gas wells are drilled using a drilling rig or a drilling ship. There are three main categories of offshore rigs. What all three of these types of rigs have in common is that they need to provide three things: stability, safety and sufficient space for the large amount of equipment drilling requires.

Figure 1.2 Jackup Rig

Jackup-rigs: are bottom-supported rig units with three or four legs that are lowered to the point where they penetrate the seabed. They are intended for shallow water with a maximum depth of 90 m, and a maximum drilling depth of 9.000 m. Day rates typically reach \$30.000 – \$150.000 depending on the rig qualifications[11].

Figure 1.3 Semi-submersible rig

Semi-submersibles: are floating units with a deck connected to pontoons that sit beneath the surface of the water. They can either be moored in place through a series of anchors, or they can be equipped with computer-controlled thrusters for Dynamic Positioning (DP). They are intended for water depths up to 3.700 m, and the day rates typically reach \$200.000 – \$500.000[12].

Figure 1.4 Drillship

Drillship: is a ship with onboard drilling equipment and is often constructed specifically for deep-water drilling. Drillships have higher load capacity than semi-submersible rigs, but are more exposed to harsh

10 UBS Investment Research – Global Oil & Gas (2008) *p.8*

11 UBS Investment Research – Global Oil & Gas (2008) *p.16,* and www.rigzone.com See Appendix 3

12 UBS Investment Research – Global Oil & Gas (2008) *p.17*

environments. It therefore depends on how the weather is in the specific area of drilling. In the Gulf of Mexico, where the water tend to be calm, drillships may be used, but in harsh areas as the North Sea, operators need to use drilling rigs. Day rates normally lie within \$100.000 – 150.000[13].

1.1.3.3 Platform Supply vessels

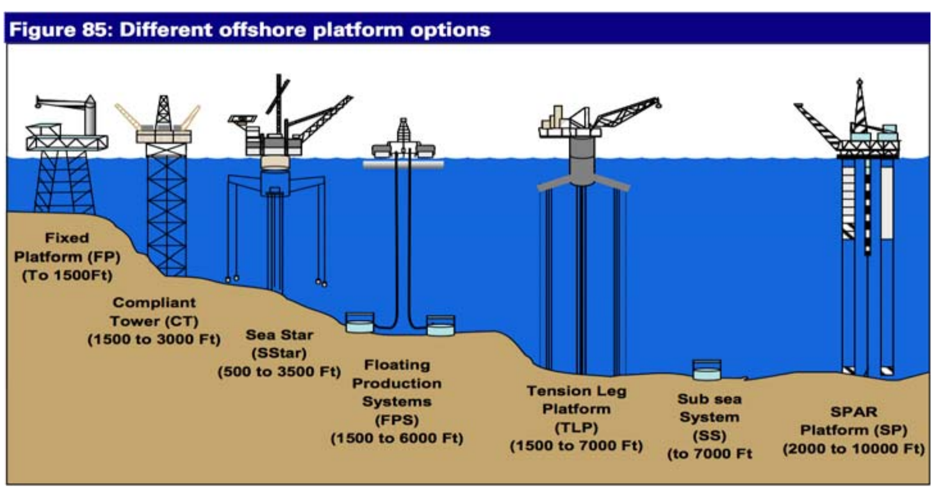
Platform Supply Vessels (PSV's) are ships specially designed to supply offshore oil platforms with fuel, food, water, chemicals, drill pipe, casing, cement etc. They can also act as an offshore storage facility when deck space becomes tight, or as transport of personnel from shore or from rig to rig within a field. These ships range from 20 to 100 meters, with up to 20 crewmembers[14].

Figure 1.5 Platform Supply Vessel

1.1.3.4 Production

There are several different types of offshore production platforms, depending on the depth of the waters where they operate. In shallow waters, the platforms usually stand directly on the seabed and are constructed from steel or concrete. Examples of such platforms are the Fixed Platform (FP) and the Compliant Tower (CT). In deeper water, inelastic platforms fixed to the seabed become too expensive. Some of the most popular solutions in developing "deep water" fields are described below.

Figure 1.6 Different production platforms



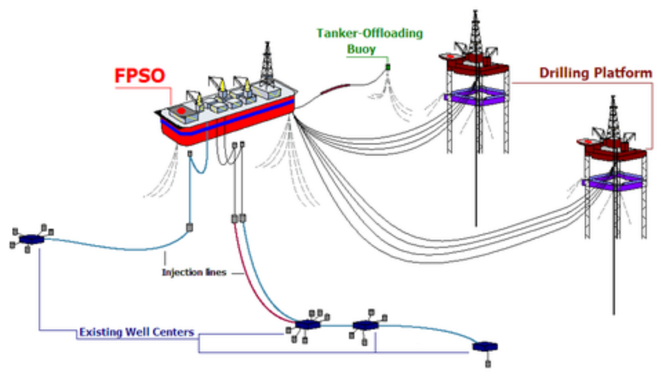
Source: Deutsche Bank - Oil and gas for beginners (2010) p.71

13 UBS Investment Research – Global Oil & Gas (2008) *p.17*

14 Wikipedia – Platform supply vessels

Floating Production Storage and Offloading (FPSOs): FPSO vessels are a popular solution in developing "deep water" fields. A FPSO is typically a converted tanker that accepts oil production from subsurface wells and processes the fluids on board to produce crude oil (as seen in). The crude oil is then exported to international markets, by shuttle tankers that moor next to the FPSO. FPSOs can range in specifications: from simple barge-like vessels anchored via chains, to vast dynamically positioned ships capable of separation of the oil constituent parts, storing of over 2 mmboe, and re-injecting produced water or gas for increased pressure and flow rate from the basin[15].

Figure 1.7 FPSO Production Opportunities



Tension Leg Platform (TLP): Is a vertically moored floating structure. It is held in place by vertical tendons connected to the seafloor by pile-secured templates, and held in tension by the buoyancy of the hull. The great stability allows a portable rig to be installed on the TLPs deck, and have direct access to wells for maintenance. TLPs have very limited storage capability, and are used where there is a local pipeline infrastructure[16].

SPAR: is a large-diameter single vertical cylinder with a deck on top, which relies on anchor-spread mooring to maintain its position. The typical diameter of the hull is 40 m, with an overall height of approximately 200 m (about 90% of the structure is underwater). SPARs are relatively cheap to fabricate, but are sensitive to large vertical movements in rough seas, and have limited deck area[17].

15 Deutsche Bank – Oil and gas for beginners (2010) *p.72*

16 UBS Investment Research – Global Oil & Gas (2008) *p.16*, Deutsche Bank - Oil and gas for beginners (2010) *p.72*

17 Global security – SPAR-platform

1.1.3.5 Refinery

Refining is the process of converting crude oil into end products like gasoline, jet fuel, diesel, asphalt etc. in other words; it is the process that gives oil value to the end customer. Refining is divided into three processing categories: separation, conversion and treatment.

Separation: is simply to distil the crude oil into its constituent parts (separate oil, gas, butane, methane, propane). As the various components have different boiling points separation at different stages is possible when the temperature rises. Different oil has different mixes of the components; heavy oil produce a large part of oil and gas, and lighter oil produce a higher proportion of lighter fractions like butane and propane. The variation of these mixes accounts for most of the crude oil difference in value.

Conversion: includes cracking which reduces the molecular structure of the hydrocarbons using heat, pressure, and hydrogen individually or together. It transforms heavy oil into lighter products such as gasoline, and light distillates.

Treatment: is when the output of the conversion units is blended to obtain minimum product quality standards. Unlike conversion, the composition of the hydrocarbons are not altered, but is rather enhanced through addition or dilution[18].

1.1.3.6 Typical life cycle of an oil field[19]

There are many factors that can determine how a life cycle of a field turns out to be. A company can acquire an oil field one year without doing anything with it in several years, as long as the licence agreement allows it. The overview in Figure 1.8 shows a typical time line from acquisition to closure of the field.

18 Deutsche Bank - Oil and gas for beginners (2010) *p.155*

19 Deutsche Bank - Oil and gas for beginners (2010) *pp.45-49*

Figure 1.8 Typical life cycle of an oil field

Year 0
- The company is given an exploration licence for a field by the oil authority in the country concerned, or they may buy it from another oil company.

Time: 3-5 years
- Geological surveys
  - Seismic surveys, gravity surveys, magnetic surveys

Time: 1-4 years
- Exploration/appraisal drilling
  - Exploration wells are drilled to determine the presence of gas or oil
- If the exploration drilling is successfull, additional wells are drilled to determine the extent of the reservoir

Time: Approx 1 year
- Development plan
  - Planning of the production and how the fields should be operated.

Time: 3-7 years
- Development of the field
  - Procurement and installation of materials and services.

Time: 10-30 years
- Production and sales
  - Production is normally ramped up for a short period of time, until the peak production level is reached
  - Peak production is maintained for a period until it naturally starts to decline. Injection wells are then drilled to raise the pressure.

Time: approx. 1 year
- Closedown of the oil field
  - When the field no longer can be commercially drifted, the company is obliged to remove all equipment from the site and restore the area if necessary.

Source: Own work based on: Deutsche Bank. Oil and Gas for Beginners 2010, pp. 45-49

The timeline in the figure is of course standardized, and the different phases overlap each other. The development planning of the field often starts as soon as contingent reserves are discovered, and runs parallel to continuing appraisal drilling. It is therefore not possible to present an exact overview, and the timeline must be looked on as guiding.

1.1.4 Market Overview

There are large differences between the countries with oil and gas reservoirs. When talking about the oil industry it is often divided into developed markets and frontier markets.

1.1.4.1 Developed markets

Many oil fields are approaching the end of their Production Life Cycle (PLC) after three decades of production in developed countries. An example is the North Sea where 40 fields already have been decommissioned, and another 66 are waiting in turn[20]. The same trend is seen in other developed fields such as the Gulf of Mexico and Alaska. As the asset base in the developed areas is declining, and the potential exploration upside is diminishing, putting a large amount of money into squeezing the last oil out of an oilfield might not make economic sense considering possible investments in undeveloped areas.

As a result of the above, a decrease in the daily production has been seen in many of the developed countries over the last decade. Examples to be mentioned are the UK which saw its production decline from a peak in 1999 of 398 million barrels to 220 million barrels in 2007[21], or Norway which has seen its production decline the last 11years[22], with a further decline of 5% in 2011[23]. This leads to a continuously pressure on the larger oil companies to develop more efficient technology.

1.1.4.2 Frontier markets

Undeveloped areas are, as opposed to developed areas, in the beginning of their PLC. Africa is such an area and the development is said to be approximately in year 5-6 compared to mature and developed oil producing countries. Many fields in Africa can be placed in the early E&D phase, and the probability of exploration success is higher than in the developed areas. As seen in the life cycle of an oil field in Figure 1.8, the development time from first discovery to first production can take many years, and in Africa the logistical and political factors are especially challenging as infrastructure must be built from scratch.

During the last three decades, technology that aims to make production and development more efficient, secure, and cost effective have been developed in the oil producing countries. This technology is readily available to be used in development of oil fields in frontier markets such as Africa. The possibility of utilizing this technology from the first stage in the oil fields life cycle is a clear advantage for companies operating in undeveloped areas.

20 Deutsche Bank – Oil & Gas for Beginners (2010) *p.49*

21 United Kingdom National Accounts – The Blue Book (2011)

22 Bloomberg – Norway Oil Output Drop 6%

23 Rigzone – Norway 2011, Total Oil & Gas Production Falls 5%

1.2 Company Description

Tullow (Tullow) is Africa's largest independent E&P company with a vision to become the leading global independent E&P company. Their assets are located mainly in Africa, but they also have operations in Europe, South America and South Asia[24]. Tullow therefore has a diversified asset portfolio spread worldwide, with operations in 22 countries and over 100 licences covering 280,000 square kilometres of acreage[25].

Tullow has production in nine countries including the Jubilee offshore production field in Ghana, which is their largest discovery and highest planned daily production to date[26]. Employing over 1.500 people worldwide Tullow has grown significant over the last decade[27]. Through thorough research and "knowhow" on how to operate in areas such as Africa, they now have every opportunity to grow further and develop their assets.

1.2.1 Vision and Strategy

Vision: Tullow's vision is to become the leading global independent E&P company.

Corporate Objective: To deliver substantial returns to shareholders.

Strategy: To achieve substantial long-term growth through balanced funding, exploration and production in core geographical areas.

1.2.2 History

Tullow was founded in 1985 and signed its first licence in Senegal in 1986. They started operations in South Asia in 1990 and the UK in 2000. In 2004, they doubled their size with the acquisition of Energy Africa, followed by the acquisition of Hardman Resources in 2006. In 2007, they made their largest discovery, the Jubilee field offshore Ghana. In the following years, several further discoveries were made in Ghana including the prospects Enyenra, Tweneboa and Teak. In 2010, Tullow completed the acquisition of Heritage Oil's licenses in the Lake Albert Basin in Uganda where 1,1bn barrels of oil have been discovered so far. In March 2012 a farm-down of the area was made with CNOOC[28] and Total, each with one third of the area´s interest[29].

24 Tullow decided to dispose their Asian assets in March 2012

25 Tullow: Annual report 2011 – *p.2 & p.5*

26 Tullow: Full year result 2011 – *pp.4-11*. The nine producing countries include the Asian assets, Pakistan and Bangladesh.

27 Tullow: Annual report 2011 – *p.2*

28 China National Offshore Oil Corporation

29 Tullow: Tullow at a glance

1.2.2.1 Historical Timeline

Year	Events	Revenue	Reserves	Number of countries
1985	• Tullow Oil is founded • Founder: Aiden Heavey • Licences obtained in Senegal	-	-	-
1986	• The first years • Gas production and sales commenced in Senegal. Acquired exploration acreage in UK, Spain, Italy and Yemen • Shares listed on London and Irish stock exchanges	$3m	-	8
1990s	• Steady progress • Activities relinquished in four countries • First licence agreement and gas discoveries in Pakistan. Licences acquired in Bangladesh, India, Côte d'Ivoire, Egypt and Romania	$10m	79 mmboe	8
2000	• Major UK acquisition • $134m acquisition of producing gas fields and related infrastructure in the UK Southern North Sea. • Catalyst for the group's positioning as a leading player in the CMS and Thames/Hewett areas.	$11,6m	73 mmboe	8
2001+	• Defining period • Growing production in core areas and integration of UK acquisition. Strong increases in sales and profits. • Financial resources and managements attention on offshore UK, West Africa and South Asia	$188,1m	70 mmboe	8
2004	• Doubled in size • Energy Africa acquisition main result of a doubling of the Group's size. Overall $1 billion spent on acquisitions and investments. Record levels of production, sales revenue, profits and cash flow.	$432,2m	326 mmboe	8
2005	• Continous growth • Integration of Energy Africa progressed well. Discoveries in North Sea, Gabon and Mauritania.	$765,9m	358 mmboe	15
2006	• Transformational year. • 5 new oil discoveries in Uganda secures its position as a world-class major new oil province. • 58% overall exploration success with 7 discoveries in 12 wells. • $1.1 billion acquisition of Hardman Resources Limited.	$1.066,7m	506 mmboe	22
2007	• Largest discovery ever • The discovery in the Jubilee field offshore Ghana marked the discovery of a second new major oil province. • 100% exploration success rate in Uganda, 56% exploration success rate overall (9 out of 16 wells)	$1.279,5m	551 mmboe	23
2008	• Best year so far • Best year from an exploration, operational and financial perspective. 77% overall exploration success. • Refocused assets from mature UK assets to its major projects in Africa	$1.310,6m	825 mmboe	22
2009	• Period of transition • Financial results in line with market expectations, reflect the development stage the company is in. • Record 87% exploration success rate (13 out of 15 wells).	$915,9m	894 mmboe	23
2010	• First Oil in the Jubilee field in record time within 5% of budget. • 83% exploration success rate (24 out of 29 wells) • Completed acquisition of Heritage Oil's Ugandan Licences	$1,089.8m	1,388 mmboe	22
2011+	• Rapid growth • Working interest production up 35% • $2.9 billion farm down to CNOOC and Total in Uganda completed • 74% exploration success ratio	$2,3 billion	1.139 mmboe*	22

* After Ugandan Farm-down

Source: Own work based on: Tullow Oil: History and Performance. Annual Report 2003-2011

1.2.3 Focus areas

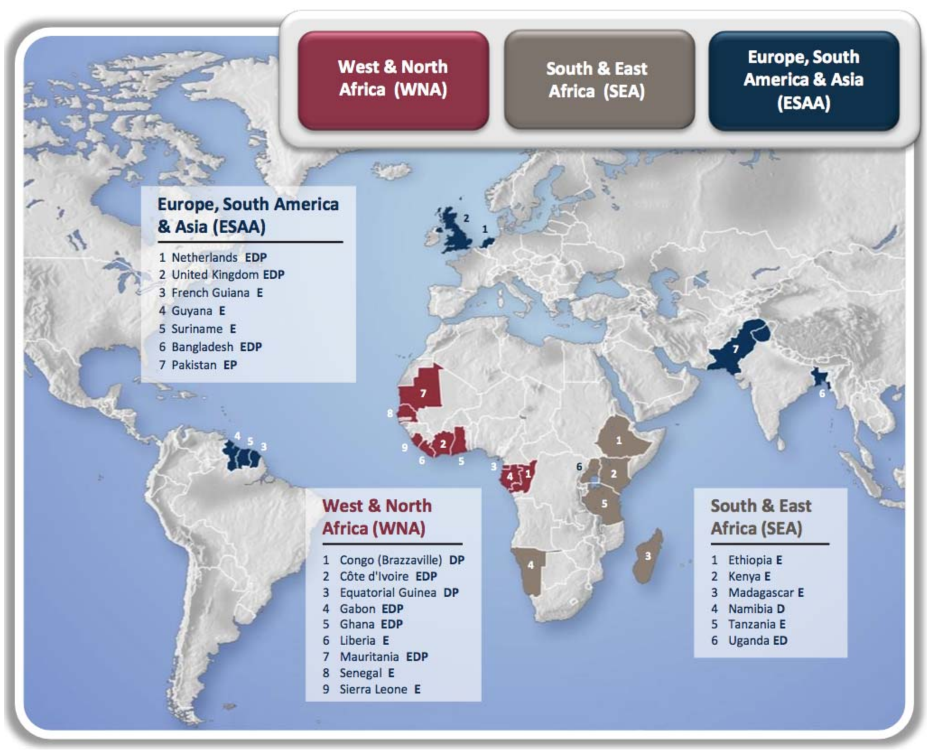
Tullow's main geographical focus areas are Africa and related geological plays in South America. These two areas are the ones Tullow believe will be essential if it is to become the leading global independent E&P company.

The company have different operational priorities, and they present the most important factor in achieving their vision as: "*Executing selective, high-impact exploration programmes funded by surplus cash flow or equity, delivering major projects, with a significant focus on increasing bankable reserves, and managing their assets to high-grade the portfolio, replenish upside and assist funding needs*"[30].

1.2.4 Areas of operations

The map below illustrates the countries in which Tullow has operations, and what kind of operations they have in the respective country[31]. A more detailed description of the different areas of operations is to be found in part 2.2 – Asset base.

Figure 1.9 Areas of operations (including Asian assets that are to be sold)



Source: Tullow Plc, Full Year Fact book 2011

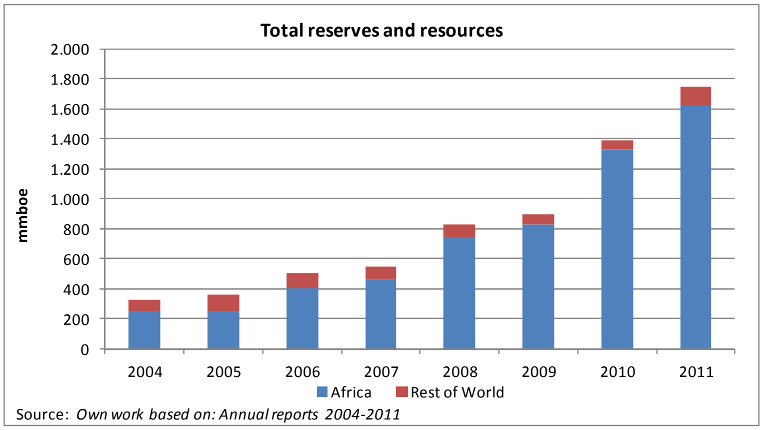
30 Tullow: Company Profile 2011 – *p.1*

31 E = Exploration, D = development, P = production

1.2.5 Reserves and resources development

Figure 1.10 shows the development on total resources from 2004 to 2011.

Figure 1.10 Development in total reserves and resources

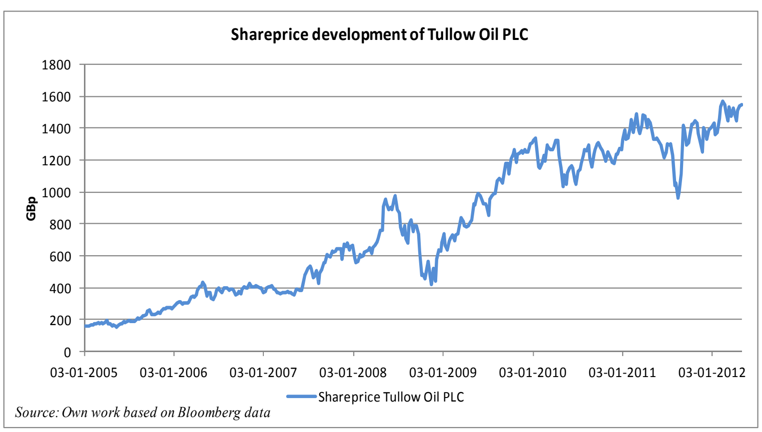


As seen in Figure 1.10, Tullow's main area of operation has been Africa throughout the whole period, and it still is today with approximately 93% of the booked reserves. In the end of 2011, the company had total reserves of 1.743 mmboe[32] which is an increase of 25% since 2010.

1.2.6 Share Price Development

Figure 1.11 shows the share-price development of Tullow over the last 7 year, while Figure 1.12 shows the share price development compared to the FTSE 350 – Oil&Gas index[33] in the same period.

Figure 1.11 Share-price development of Tullow PLC

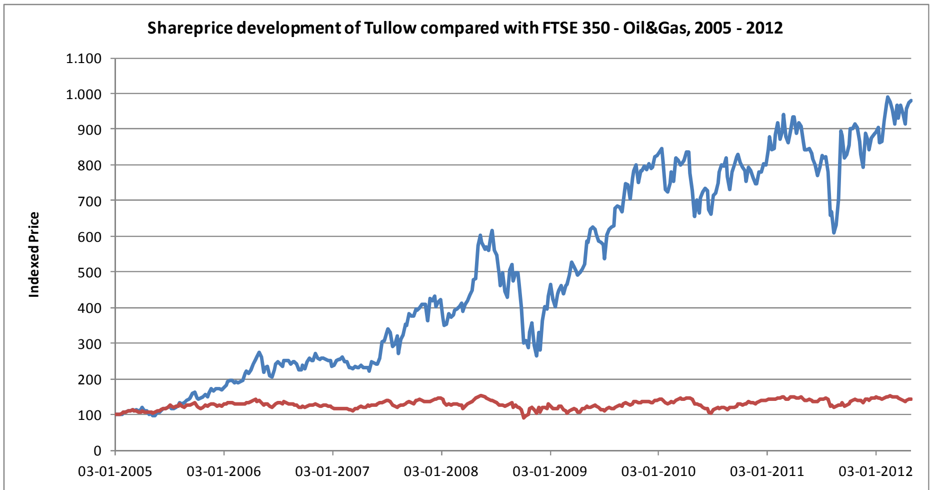


32 After the Ugandan farm down, total reserves amount to 1.139 mmboe

33 FTSE 350 – Oil and Gas index is commonly used as benchmark for oil companies, because most of the international players within the industry are listed on LSE.

The share-price has increased steadily with exception of two decreasing periods. The first decrease was mid 2008, when the share price dropped over 50% as a result of the global financial crises, and the decrease in the oil price. The second large drop came as a result of the listing on the Ghana Stock Exchange in 2011. 4000.000 shares were offered at a discount of 2,57% compared to the closing price of a Tullow share on the London Stock Exchange the day before. At the same time, the markets were stressed due to the European debt situation that emerged among the Southern European Countries. See part 3.3.1.1 - Oil Price.

Figure 1.12 Share-price development of Tullow compared with FTSE 350 - Oil&Gas



Source: Own work based on Bloomberg data

Tullow's share price closed at 1.534 pence per share the 30th of April. Figure 1.12 shows the share price development of Tullow compared to FTSE 350 – Oil&Gas index over the last 7 years. Tullow's has clearly outperformed the index, and is currently trading at approximately 10 times what it did 7 years ago, while the FTSE 350 – Oil&Gas only has increased around 50% in the same period.

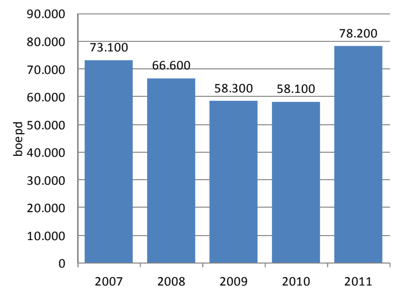
1.2.7 KPI

E&P companies do not present any long-term goals other than their overall vision and objectives, and give only a guiding for the exploration and appraisal the next 12 months. The reason for this is that they need to have an on-going evaluation of what assets that should be developed and how the CF should be prioritized. In addition, the oil price is very volatile, and the strategy may therefore change drastically if the oil price falls or rises significantly.

Instead of long-term specific financial or exploration goals, they present goals on more overall metrics such as total production and safety. These goals are referred to as their Key Performance Indicators (KPIs), and are presented below.

__Working interest production:__ WI production targets are set as part of the group's annual budget process. Production is the key element to revenue and cash generation, and part of their long turn strategy is to grow the production profile to fund a $700 - $1000 million exploration programme per year[34]. The group's baseline production target for 2011 was 87.800 bopd, while actual production was 78.200 and they did hence not meet their target. Production is expected to rise substantially in the years to come.

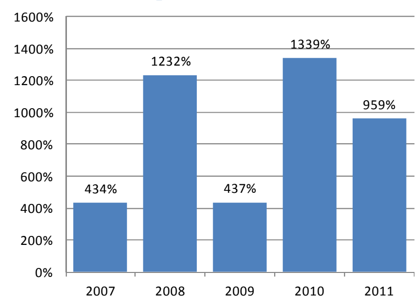
Figure 1.13 WI production



Source: Own worked based on: Annual Reports 2007-2011

__Reserves and resources replacements:__ Replacement of reserves and resources is a key measure for exploration success. It measures the amount of proved reserves added to a company's reserve base during the year relative to the amount of oil and gas produced[35]. In 2011, Tullow had a reserve replacement of 959%, which means that they discovered over 9 times more barrels of oil than what was produced. Their five year average is 880% which is very good compared to an industry benchmark of 234%[36].

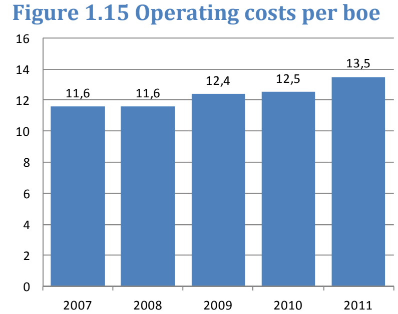
Figure 1.14 Reserves and resources replacement



Source: Own worked based on: Annual Reports 2007-2011

__Cash operating costs per barrel of equivalent (boe):__ Cost per boe is an important measure to see how Tullow's operating costs are compared to their peers and relative to their targets. In 2011 they set a baseline target of $12,8 per boe, while their actual operating costs where $13,5 per boe. The reason why they didn't reach their target was because of lower than expected production in the Jubilee field, resulting in fewer barrels produced to "share"

Figure 1.15 Operating costs per boe



Source: Own worked based on: Annual Reports 2007-2011

34 Tullow: Annual Report 2010 – *p.10*

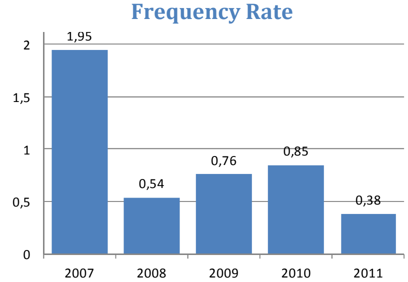
35 Investorpedia: Reserve-replacement ratio

36 Ernst&Young: Oil and Gas E&P benchmark study – *p.10*

the fixed costs. The company's five year average is $12,32 which is slightly higher than the five-year industry benchmark of $12,09[37].

LTIFR: The Lost Time Injury Frequency Rate, or LTIFR, measures Lost Time Incidents (LTI) per million hours worked. LTI is an accident resulting in personnel not being able to work because of their injury. The last five years, they have had a baseline goal of a LTIFR < 1 and a stretch goal of < 0,5. They beat their stretch goal in 2011 with a LTIFR of 0,38 putting them in the top quartile of their industry[38].

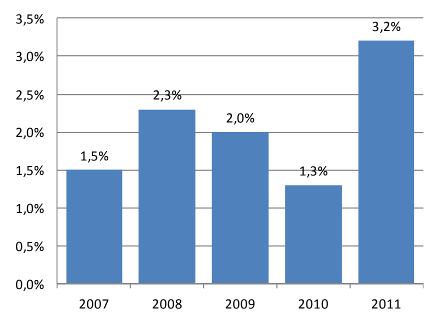
Figure 1.16 Lost Time Injury Frequency Rate



Source: Own worked based on: Annual Reports 2007-2011

Staff turnover: With over 1.500 employees worldwide, talent management and succession planning are very important for future growth. It is important to avoid unexpected departures and suddenly lacking people skills to perform the tasks necessary at any given moment. Employees who leave the company are debriefed to disclose the reason for departure to be better equipped to retain the best people. In 2011, the company has a staff turnover of 3,2%, which means that during the year, 3,2% of the workers were replaced by new employees.

Figure 1.17 Staff turnover



Source: Own worked based on: Annual Reports 2007-2011

1.2.8 M&A track record

There are four major acquisitions in Tullow´s timeline that it is worth to taking a closer look at. These four are the acquisition of the UK North Sea gas assets in 2000, the acquisition of Energy Africa in 2004, the acquisition of Hardman Resources in 2007 and the acquisition of Heritage Oil´s Ugandan licences in 2010.

Early in 2000, Tullow announced that it would acquire producing gas fields and related infrastructure in the UK Southern North Sea from BP, for a consideration $387m (£201m). The acquisition included the CMS and the Thames area, and the North Sea became a new area of operation which demanded the management's attention and the company's financial resources. The acquired areas were successfully integrated in Tullow´s portfolio in

37 Ernst&Young: Oil and Gas E&P benchmark study – *p.*11

38 Tullow: Annual Report 2011 – *p.*33

2001, with first gas in 2002[39]. The acquisition was a catalyst for their positioning as a leading player in the North Sea, and through success in several licensing rounds the following years, 16% of Tullow's total production in 2011 came from the UK gas fields. In addition, these "safe" assets are, through their cash flow, funding the E&P activity in the frontier markets.

In May 2004 the $601.1m acquisition of Energy Africa was completed[40]. The acquisition added 14 producing fields, and 37 exploration licenses to the Group's portfolio. In combination with Tullow's existing African interests, the acquisition created a diversified pan-African oil and gas business. The lower operating costs of the Energy Africa portfolio reduced the overall operating costs from $8,54/boe in 2003 to $8,44/boe in 2004, and increased the Operating Cash Flow from $155m to $296m in the same time frame[41].

Tullow announced in Q3 2006 the acquisition of Hardman Resources for a price of $1.1bn, which made it the Group's largest acquisition ever. The acquisition materially enhanced its operations in Mauritania and Uganda, and added high-impact exploration licences in South America. The group obtained 100% operated interest in Block 2 in the Lake Albert Rift Basin in Uganda, which was of strategic importance for future development. The area has easy access to the lake shore, the level terrain for operations is good and an export route to the coast was feasible[42]. The acquisition also included licences in Suriname and French Guinea, which formed the basis for their operations in South America. Today these licences represent some of Tullow's most promising reserves, due to similar geology as in West Africa[43].

In July 2010, Tullow completed the acquisition of Heritage Oil´s Ugandan licences in the Lake Albert Rift Basin for a price of $1,45bn. The acquisition included a 50% interest in Exploration Areas 1 and 3A, increasing Tullow´s WI to 100%. The acquisition enabled Tullow to start planning a farm-down process, which resulted in the $2.9 billion farm-down with Total and CNOOC in the Lake Albert Rift Basin in 2012.

39 Tullow: CMS Area report – *p.33*

40 Tullow: Annual Report 2004 – *p.35*

41 Tullow: Annual Report 2004 – *p.38*

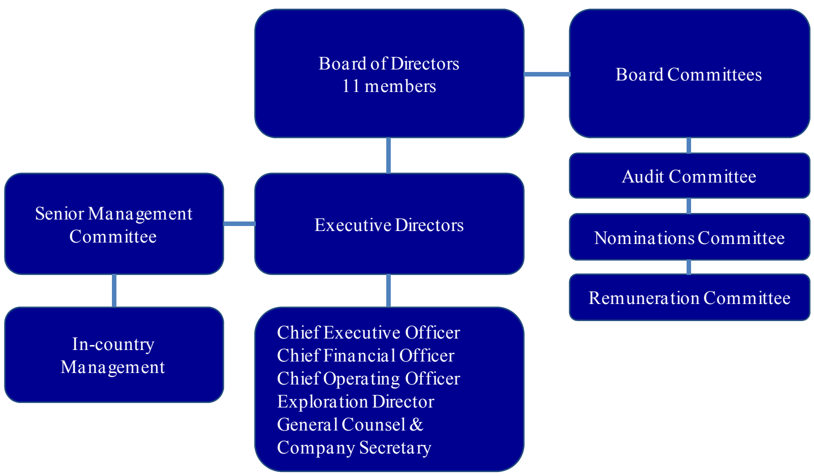
42 Tullow: Annual Report 2006 – *p.8*

43 Se part 2.2.4West African Jubilee Play (WAP) for further description of the similarities

1.2.9 Organisation and Management

The company is organized with a Board of Directors consisting of 11 members in total, whereas six of them are non-executive including the Chairman. The board has an audit committee, a nomination committee and a remuneration committee. The company has five executive directors, including founder and CEO Aidan Heavey and CFO Ian Springett. The Senior Management Committee (SMC) is responsible for the day-to-day management of Tullow's Business, and works directly with the Executive Directors keeping them fully informed of opportunities and business issues across the company and the industry. The SMC is also responsible for ensuring safe delivery of the agreed annual budget and plan an effective risk evaluation, management and mitigation[44].

Figure 1.18 Organizational structure[45]



1.2.9.1 Ownership Structure

Tullow's main listing is on the London Stock Exchange, and they have secondary listings on the Irish Stock Exchange end the Ghana Stock Exchange. Tullow has only one share class. Voting on matters at general meetings is either by a show of hands or a poll if it is duly demanded. On a show of hands, every shareholder present at the general meeting has one vote regardless of the number of shares held by the shareholder. On a poll, every shareholder who is present in person has one vote for every share held by that shareholder, and every corporate representative may exercise one vote for every share the represented

44 Tullow: Board and Management

45 A more thorough overview over the company´s organization can be found in appendix 5.

company has. There are a total of 905 million shares listed; the four major shareholders and the directors' holdings are listed in Table 1.1[46].

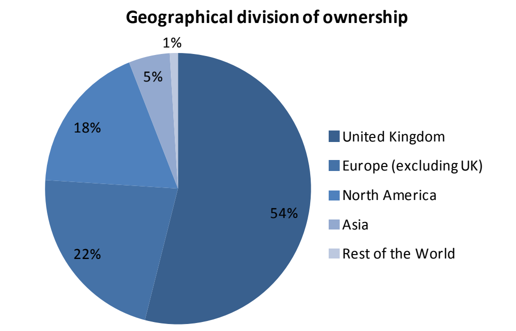
Table 1.1 Major shareholders and directors' holdings

Shareholder		Nr. of shares	% Holding
Blackrock Inc		106.568.436	11,99%
Prudential PLC		63.386.247	7,01%
IFG International Trust Company Ltd		38.960.366	4,40%
Legal & General Group PLC		35.414.975	3,99%
Name	**Title**	**Nr. of shares**	**% Holding**
Aidan Heavey	CEO	6.401.511	0,72%
Paul McDade	CFO	268.153	0,03%
Graham Martin	General Counsel & Company Secretary	1.710.118	0,19%

Source: Own work based on: www.tullow.com – Major shareholders

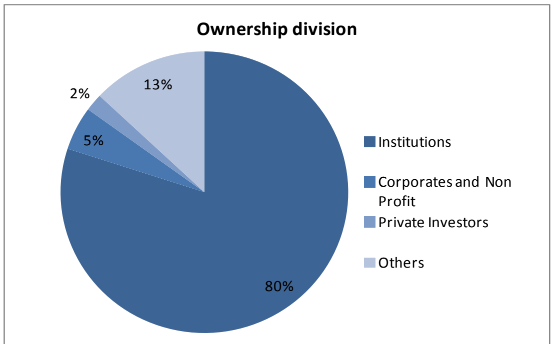
Figure 1.20 and Figure 1.19 illustrates the division between different kind of owners, and where the investors are located.

Figure 1.20 Geographical division of ownership



Source: Own work based on: *www.tullowoil.com - Shareholder analysis*

Figure 1.19 Ownership Division



Source: Own work based on: *www.tullowoil.com - Shareholder analysis*

As seen in Figure 1.20, the largest part of shareholders are listed in United Kingdom (54% of shares), while shareholders in the rest of Europe and North America accounts for respectively 22% and 18% of the shares. Figure 1.19 shows that institutions account for 80% of the shares, corporate and non-profit accounts for 5%, while private investors accounts for 2%. As financial institutions normally can be seen as long-term investors, this could have a stabilizing effect on the share price, and mitigate the volatility created by day-traders.

46 Tullow: Shareholders right

2 Strategic Analysis

This section is divided into two main parts. The first part concerns the factors in Tullow's operations that are of greatest strategic importance, while the second part gives a thorough description of the company's assets base.

2.1 Factors of strategic importance

2.1.1 Political risks

There are political risks associated with operating within the oil business worldwide. Oil and gas production play a significant role in the economy of oil producing countries, as it is an important source of revenue through taxation. For Tullow, these risks are of special importance as most of its operations are in Africa, where the majority of the countries are in a developing phase both economically and politically, and thus hold larger operating risks. Working in countries with a different political development and culture requires knowledge about the political situation and issues. Tullow's operational experience in the region works at their advantages in this matter. They have also focused on recruiting local workers and local management with knowledge about the issues in the region.

The Corruption Perception Index ranks countries based on how corrupt a country's public sector is perceived to be[47]. According to the CPI 2011, see Table 2.1, at a scale from 0 (highly corrupt) to 10 (highly clean), the African countries Tullow operate in all score under 4.4, being perceived as corrupt. Countries such as Uganda and Kenya, where Tullow has a large upside potential in oil reserves, have as low values as 2,4 and 2,2, ranked respectively as 143 and 154 in the world. This poses a clear risk for Tullow as corruption can make the political environment unstable, and because of the possible problems being associated with involvement in a corruption case.

47 Transparency International: Corruption by Country

Table 2.1 Transparency International – Corruption Perception Index

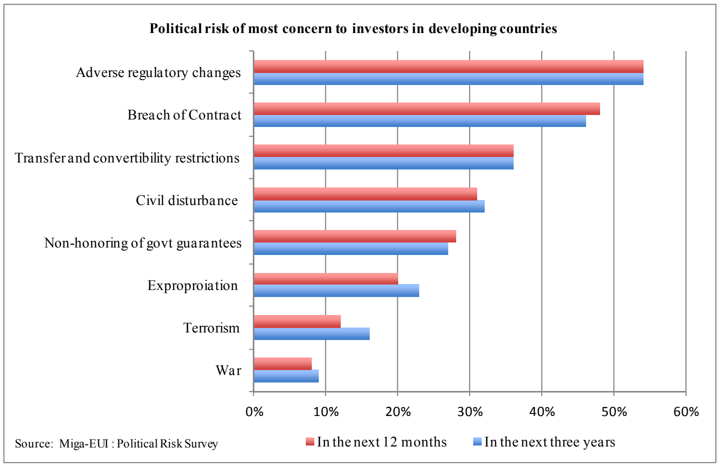
Country	Rank	CPI (2011)	Rule of law
Africa			
Namibia	57	4,4	0,62
Ghana	69	3,9	0,54
Gabon	100	3	0,36
Madagascar	100	3	0,24
Tanzania	100	3	0,36
Senegal	112	2,9	0,42
Ethiopia	120	2,7	0,27
Sierra Leone	134	2,5	0,18
Liberia	143	2,4	0,11
Mauritania	143	2,4	0,22
Uganda	143	2,4	0,42
Congo	154	2,2	0,12
Ivory Coast	154	2,2	0,09
Kenya	154	2,2	0,17
Equatorial Guinea	172	1,9	0,09
South America			
French Guiana	25	7	0,86
Suriname	100	3	0,52
Guyana	134	2,5	0,39
Europe			
UK	16	7,8	0,95
Netherlands	7	8,9	0,97

Source: www.transparency.org

Table 2.1 also presents what Transparency International defines as the "Rule of Law". The Rule of Law captures perceptions of the extent to which agents operating in the country have confidence in and abide by the rules of society, and in particular the quality of contract enforcement, property rights, the police and the courts[48]. As an example, the value of 42% in Uganda means that less than 42% of the agents included in the survey have confidence in the quality of contract enforcement or property rights, among others. We see that many of the countries Tullow operates in have a "Rule of Law" percentage under 50%, which should be taken into account in the valuation. The Multilateral Investment Guarantee Agency recently published a report that shows that the biggest political risk concerns of multinational corporations in developing countries are adverse regulatory changes and breach of contract. These factors are considered much more risky for business than conflicts such as war, terrorism and expropriation, as can be seen in Figure 2.1.

48 Transparency International: Corruption by Country

Figure 2.1 Investors perception of political risk



The fact that the countries Tullow operates in score low on the "Rule of Law" governance indicator implies that the risks connected to factors such as adverse regulatory changes and breach of contract are especially severe here.

2.1.1.1 Quantifying the political risk

The above mentioned political factors will be elaborated in part, where each country will be discussed further in association with incorporating the political risk in the risk weighting of the different fields.

2.1.2 Corporate Governance

When valuing a company the management plays an important role because they are accountable for the overall company strategy. In the E&P sector, management is even more essential because of the long PLC in the industry. Analysing the management and their accomplishments in different areas gives an indication of their future trend line.

Table 2.2 Key Management

Position	Years with the company	Sector Experience
CEO Aidan Heavy	27 years	27 years
CFO Ian Springett	4 years	27 years
Chairman Patric Punkett	14 years	14 years
Exploration Director Angus McCoss	6 years	27years

Source: Bloomberg

Tullow has been present in Africa since the 1980's, which has provided good local knowledge about the industry and the political environment. They have been aware of the importance of having a good relationship with the local governments and communities to avoid unwanted surprises, and they focus on including locals both in their production and the local management[49].

In the development of the Jubilee field, Tullow set a new industry benchmark. They managed to commence production within 3.5 years against an industry benchmark of 5-7 years[50]. Doing this proves the well planning and execution controlled by the management on their first deep-water project of this size.

Tullow´s history of Mergers and Acquisitions[51] (M&A), with continuously farm-ins and farm-downs, Supports the management's competence in assessing operational risk, and their expertise in asset picking. An example is in Uganda where they decreased both operational and financial risks through a farm-down. They have also done several farm-ins to secure future potential asset upside, and their track record in terms of success within these M&As is very good. This implies, supported by the analysts talked with[52], that the company uses more capital than its peers to fully understand the basins before going through with a farm-down/in.

2.1.3 Exploration success rate

One of the main things that distinguish Tullow from other E&P companies is their good track record of successful exploration drillings (high exploration success rate). Table 2.3 presents Tullow's drilling record in 2011[53].

Table 2.3 Exploration success rate

Country	Wells drilled	Well Success	Exploration success rate
West & North Africa			
Gabon	8	6	75%
Ghana	11	9	82%
Liberia	1	0	0%
Mauritania	2	1	50%
South & East Africa			
Uganda	9	8	89%
Europe, South America & Asia			
Uk	2	1	50%
Netherlands	1	0	0%
French Guiana	1	1	100%
Overall	**35**	**26**	**74%**
Average			56%

Source: Annual report 2011

49 Tullow: Interview with Aidan Heavey

50 Tullow: Annual Report 2010 *p.26*, Interview with USB analyst

51 See appendix 4 - M&A Track Record

52 Bernstein, Goodbody, UBS and BankInvest analysts

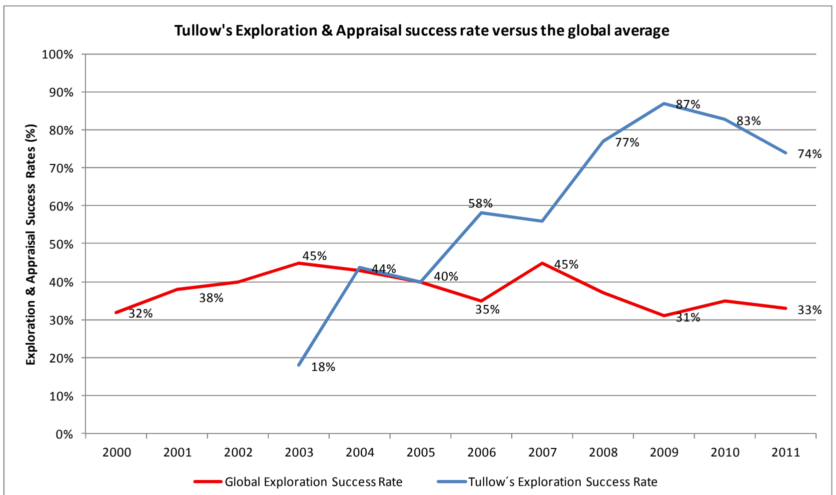
53 A complete overview over the drilling in 2011 can be found in appendix 6

With many successful wells drilled in both the Jubilee field and the Lake Albert Rift Area in 2011, Tullow continues their impressive track record with an overall success rate of 74%[54]. They drilled a total of 35 wells, and encountered oil in 26 of them.

The last five years, Tullow has had an average exploration success rate of 75,8% which is 2,1x the industry average. This success has been matched by a steady growth in carrying reserves, and their reserves grew by 1 bnboe during the same period[55].

Figure 2.2 shows Tullow's overall exploration & Appraisal success rate versus the global average the last 11 years.

Figure 2.2 Exploration & Appraisal success rate



Source: IHS, Annual reports 2003-2011, Credit Suisse Estimates

The fact that Tullow's main focus is on underdeveloped regions and stratigraphic traps makes their high success rate even more impressing. Stratigraphic traps are more difficult to identify through seismic imaging than structural traps[56]. Tullow has made such discoveries in Ghana, French Guiana and Sierra Leone.

One of the key aspects that distinguish Tullow's exploration activities from many of its peers is that they do not drill a well solely because it has a positive AVO seismic anomaly[57]. The area is also compared with similar geological areas to develop structure estimation and the possibility for further adjacent prospects.

54 This is the overall success rate calculated as the total number of successful wells against the total number of wells drilled. The average success rate for the countries is 56%.

55 Tullow: Annual reports 2007-2011

56 See appendix 10

57 Amplitude Versus Offset – Used to indicate if hydrocarbons may be present.

The success these last years has lifted Tullow´s share price and they have vastly outperformed their peers (shown in Figure 1.12 company description).

2.1.4 Peer Group

Tullow is an uncommon company compared to other companies within the E&P sector, and there are several reasons why conducting multiple valuation gives little value. There are no direct comparable companies with similar asset base as Tullow, and with the same experience in Africa. The share-price today reflects the estimated reserves and the expected future growth, which results in very high valuation multiples, indicating that the company is expensive.

In addition, many of the E&P companies do not have any revenue generation, only assets in form of potential oil discoveries. Without any revenue generation, valuation multiples as P/E or EV/EBITDA are not usable. Many of the companies are also of higher risk compared to Tullow, often because they only have exploration prospects, and no commercial or contingent prospects. These companies are almost like lotteries, if they find oil the share price will multiply, if not the share price will collapse. In other words, these are single asset players and not portfolio players as Tullow is.

A third problem in terms of comparable companies is the declining resources in the world, which drives the IOC companies in their willingness to pay for new discoveries. If an E&P company is successful, their risk of being acquired by an IOC drastically increases. This is because the IOC´s conditions for developing the potential prospect are better than the smaller E&P companies, and because the IOC´s need to secure future oil production to survive. This merger and acquisition process is well developed in the sector and Tullow is a company with a good track record within the subject, as described in section 1.2.8 M&A track record. Tullow is one of the rare examples of such a large E&P company, and due to its size and owners, little indicates that they will be acquired.

These are the most important reasons why conducting a comparable valuation analysis makes little sense when finding a fair value of Tullow. Due to the fact that multiple valuations are not used, the description of the closest peer group can be found in Appendix 14. In part 4.5.4 – Peer Group Analysis, a description and illustration of why it is difficult to use multiples will be presented.

2.2 Asset base

Tullow has 106 licences around the world, 67 of them are producing fields, all in different stages of the PLC[58]. To understand the company in its full extent, it is important to understand its main assets, and these will be presented in the next section. All of the illustrations presented are gathered from Tullow´s web page, under "Our Business", and hence listed without a source.

2.2.1 Operational View

Tullow has production/planned production in 10 countries located in Europe, South East Asia and Africa. The current production secures cash flow to finance new E&A projects, mainly in Africa. The most important areas of production and the highest upside in value creation are Ghana, Uganda, Mauritania and Kenya. Ghana is important due to the Jubilee field, Mauritania have prospects to be developed in the coming years to replace the existing production in the country, and Kenya can turn out to be a reservoir larger than the Ugandan assets in the long-term perspective. The European assets are stable and easier to value and the Asian assets are to be sold in 2012. Table 2.4 gives an overview over key statistics for countries with producing assets.

Table 2.4 Key statistics - Producing countries –between commercial/contingent and exploration values

Country	Nr. Licences	Reserves P50*	Reserves P50 Exploration	Working Interest	2011 Net Production	% of Net Production	2012 Net Production
		Net mmboe	Net mmboe	%	kboepd	%	kboepd
Africa							
Ghana	2	512	354	35%	23500	30%	28400
Equatorial Guinea	2	26	-	14%	13050	17%	10300
Gabon	21	52	21	8-40%	12700	16%	13000
Ivory Coast	3	13	152	21%	3750	5%	3000
Congo (Brazzaville)	1	10	-	11%	3000	4%	2400
Mauritania	8	404	46	19%	1400	2%	1300
Europe							
UK	16	44	-	14,1-100%	12500	16%	12200
Netherlands	19	42	11	4,1-22,5%	3000	4%	6800
South Asia							
Bangladesh	1	22	-	30%	5.200	7%	N/A
Pakistan	7	39	-	40%	100	0,10%	N/A
Sum	**80**	**1164**	**584**		**78200**		**77400**

* Commercial and contingent net to Tullow values

Source: Own work based on Tullow Oil Fact Book 2011 and Tullow Oil Annual Report 2011

Table 2.5 on the next page gives an overview over key statistics for countries without producing assets.

58 Tullow: Where we operate

Table 2.5 Key statistics - Non-producing countries - contingent and exploration values

Country	Nr. Licences	Reserves P50 Contingent	Reserves P50 Exploration	Area	Working Interest
		Net mmboe	Net mmboe	Sq Km	%
Africa					
Uganda	5	367*	185	5796	33%
Ethiopia	1	-	70	29465	50%
Kenya	7	18	404	79479	20-50%
Liberia	3	-	41	9775	25%
Madagascar	2	-	-	20100	100%
Namibia	1	155	-	4567	31%
Senegal	1	-	-	2807	60%
Sierra Leone	1	32	-	5081	20%
Tanzania	2	-	-	12360	25%
South America					
French Guiana	1	48	184	24100	28%
Gyuana	1	-	129	8400	30%
Suriname	2	-	40	4961	40-70%
Sum	**27**	**620**	**1053**		

* Uganda is classefied as commercial, but no production to date

Source: Own work based on Tullow Oil Fact Book 2011 and Tullow Oil Annual Report 2011

2.2.2 Africa

With 93% of their registered reserves located in Africa[59], the operating risk is mainly within this area. In the following section, these assets will be explained in terms of their value creation for Tullow. Reservoir information for the prospects disclosed in the following sections is commercial and contingent P50 levels, net to Tullow. For prospects included in the E&A drilling programme for 2012 and 2013, both P50 and P10 levels are provided, also these net to Tullow.

2.2.3 West & North Africa[60]

Total production	Total Commercial & Contingent reserves	Sales revenue	2011 investment
57.400 boepd	1.052 mmboe	$1.944 million	$768 million

2.2.3.1 Ghana

Ghana represents some of Tullow´s most valuable assets as of today. The offshore Ghana area is characterized as one of their main contributors to the expected increase in net oil production in the upcoming years. The area is currently still in an early phase with the Jubilee field as the first producing field. Tullow´s interest is divided into two blocks. The Deepwater Tano

Figure 2.3 Ghanaian Assets

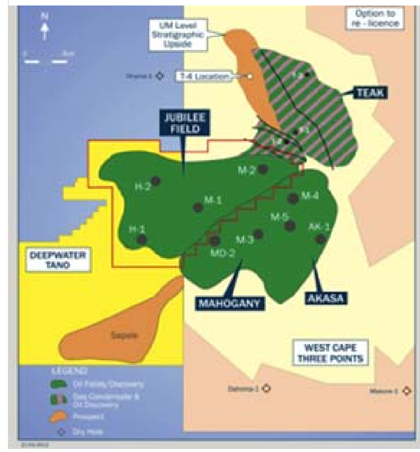
59 Tullow: Full year result 2011 – *pp. 2, 7 and 9*

60 An overview over key statistics for the region can be found in appendix 7.

(49,95% WI - operator) and West Cape Three Points (WC3, various WI[61] - not operator) with Jubilee located between these two blocks.

2.2.3.1.1 Jubilee

Figure 2.4 Jubilee field



First production from the Jubilee field in Ghana commenced ultimo 2010. The field is a milestone for Tullow´s operations in Africa due to the well-planned development phase from discovery to the production start. The company, and its partners, completed the development of the field within 5% of the budget, and set a new industry benchmark by achieving first oil within 3½ years. The Jubilee success is important for the company as they managed to handle the complexity of the field, with oil located 1.500 m below the sea level.

Today the field produces over gross[62] 70.000 barrels of oil per day (bopd), and is expected to average between gross 70.000 and 90.000 bopd in 2012, depending on the success of the Phase 1 recovery programme, and the execution schedule of the Phase 1A wells. The long term goal is to build up towards the FPSO design capacity of 120.000 bopd, through infill drilling and tiebacks of adjacent prospects. The production ramp-up has been slower than estimated with some wells underperforming, however the company is confident that this is a mechanical issue and not a reserve/resource issue and that it does not affect the long term goal of 120.000 bopd. Jubilee's ramp up is likely to reach plateau early in 2013[63].

Jubilee is only at its first out of three phases, and Tullow has a net P50[64] of approximately 240 mmboe in the prospect. The two next phases are 1a and 1b. The development of Phase 1a started in February 2012 and consists of drilling eight new production wells over the next 18 months. The first of these wells is expected to become operative during Q2 2012[65]. Phase 1a consists of tie-backs to existing FPSO´s or new cluster (partnership) developments in the field.

61 Due to Jubilee field's presence in both Deepwater Tano and WCTP. Other fields in WCTP have a working interest of 26,4%

62 Gross production is the total production on the field. Net production is Tullow´s share of the gross production

63 Credit Suisse: Tullow; Still evolving

64 P50 meaning the reserves and/or resources estimates have a 50 % probability of being met or exceeded.

65 Tullow: Full year results 2011 – P.4.

The selection and priorities regarding FPSO placements, production development and phase 1b will be determined in accordance with the E&A success from phase 1a. This will most likely commence in 2013+. DWT and WC3 are both under exploration, and seismic data is being analysed to decide locations of new appraisal wells.

2.2.3.1.2 West cape Three Points (WC3)

The WC3 area is the east block of the Jubilee field. The operator of the field, Kosmos, will during 2012 evaluate the Mahogany and Akasa Prospects for further development. During 2011, 3 new discoveries and confirmations were made in the field, north of Jubilee. Plans are in place for the Teak-4 appraisal well and flow testing in 2012, with results expected in June/July, and will direct the future development plans[66]. The Teak area might be a financial contributor to Phase 1b or the Mahogany East cluster development with a net P50 of 26 mmboe, and a potential upside of 52 mmboe. The combined net commercial and contingent P50 in the block is ~60 mmboe.

Figure 2.5 West Cape Three Points (WC3)

2.2.3.1.3 Deepwater Tano

The Deepwater Tano block west of Jubilee consist of mainly three fields; Tweneboa, Enyenra, and Ntomme, collectively known as the TEN complex. The first appraisal well (Tweneboa-2) was drilled in Tweneboa in February 2010. Combined with the findings from the 2009 exploration drilling of Tweneboa-1, the field was established as a major gas condensate and oil field. The second appraisal well (Tweneboa-3) spudded in January 2011, and

Figure 2.6 Deepwater Tano

66 Tullow: Full year results 2011 – *p.5*

drilled into the Ntomme prospect. The prospect proved to be a material and separate gas-condensate accumulation, and the first appraisal well of the Ntomme accumulation (Ntomme-2A, 4km south of Tweneboa-3) was initiated early in 2012. The well successfully discovered high quality oil-bearing reservoir below the Ntomme gas-condensate accumulation.

In July 2010, Owo-1 and several sidetrack wells were drilled west of Tweneboa, which established Enyenera as a major new oil field. In February 2011, the first Enyenra appraisal well (Enyenra-2A) was drilled, and Tullow encountered high quality light oil. The Enyenra-4a was drilled to define the southern extent of the field and intersected 32 metres of net oil pay in March 2012.

The Wawa-1 well is expected to spud in May 2012 and is considered a possible high-impact catalyst[67] with P50 levels of 30 mmboe and an upside potential of 75 mmboe. In addition to the Wawa prospect, the TEN fields are included in the 2012 exploration programme with combined net P50 reserves of 200 mmboe, with a potential upside of 400 mmboe.

A Plan of Development (PoD) for the TEN prospects and a formal declaration of commerciality are expected to be delivered to the Government of Ghana in June 2012. The plan is currently to use the same setup as with Jubilee with help from a large FPSO. First production is anticipated approximately 30 months after government approval of the PoD, or late 2015[68]. The combined net P50 reserves in the block, including the exploration programme, is estimated to approximately 470 mmboe, with a potential upside of 845 mmboe.

2.2.3.2 Liberia & Sierra Leone

Tullow has four deep-water licences offshore Liberia and Sierra Leone. The Jupiter-1 well in Liberia finished drilling in February 2012 and encountered 30 metres of net pay in multiple zones. In November 2011, the Montserrado exploration well made a non-commercial oil discovery and the Mercury-2

Figure 2.7 Liberia & Sierra Leone

67 UBS: Feedback from roadshow with COO

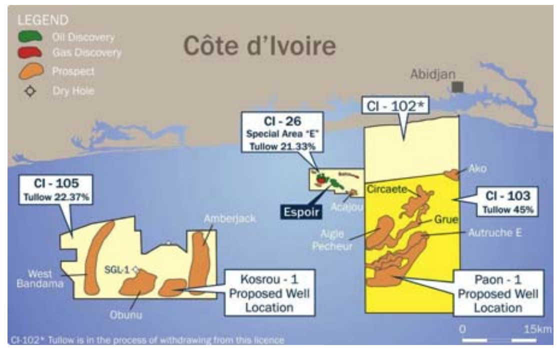
68 Ghanaian elections may slow decisions until around April 2013, but best case is 3Q 2012

exploration well was announced unsuccessful in April 2012. The Strontium exploration well in Liberia is expected to spud in 4Q 2012, with a net P50 of 41 mmboe and an upside potential of ~111mmboe. Sierra Leone has P50 commercial and contingent net reserves of 32 mmboe. Further analysis is being carried out and considered by the partners to identify follow-up exploration and appraisal targets.

2.2.3.3 Ivory Coast

In Ivory Coast, Tullow has both on-going production and future exploration plans. They are currently producing in the Espoir field (21,33% WI), where net production in 2011 averaged 3.750 boepd. The production in Ivory Coast decreased in 2010 and 2011 due to a planned shutdown to upgrade the current FPSO operating in the area. Tullow will continue with further drilling of eight infill wells to increase pressure and production in Q4 2012.

Figure 2.8 Ivory Coast

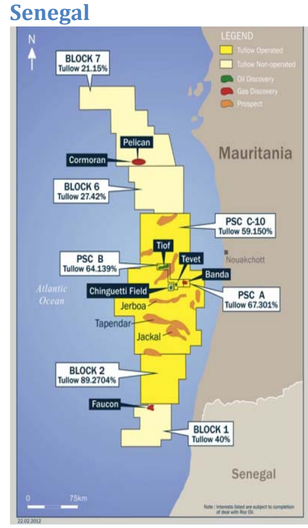


On the exploration side, there are net P50 values of 152 mmboe in Paon and Kosrou with a potential upside of 372 mmboe. The Kosrou-1 well was reported unsuccessful 19th April 2012, after yielding mainly water wet sandstones, but further appraisal drilling is planned. The Paon-1 exploration well will start drilling imminently, and is considered a possible high-impact catalyst. It is geologically different from Kosrou, and closer to the discoveries in Ghana, however little can be inferred as to the probability of its success.

2.2.3.4 Mauritania and Senegal

The Chinguetti field in Mauritania produced an average of 1.400 boepd net to Tullow (2% of the group´s total production). Evaluation of further optimization in 2012 is being conducted. Tullow signed a new Product Sharing Contract (PSC) in Mauritania during 2011, which replaces the two PSC's A and B. The operating equity is now 59%, and the area to be explored is over 10.000 sq km. The company has several exploration

Figure 2.9 Mauritania & Senegal

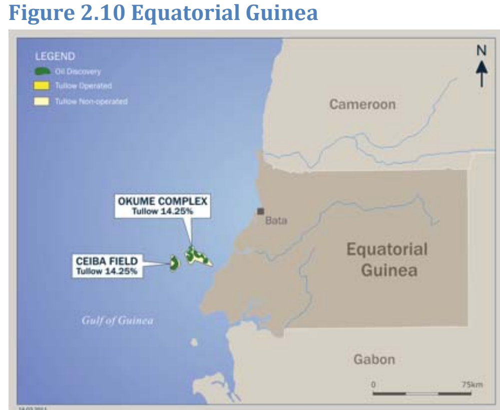


activities planned including both 3D seismic acquisition and drilling in the Mauritania-Senegal basin during 2012.

Tullow has appraised the Pelican gas discovery in block 7, to explore the two underlying exploration prospects, Cormoran and Petronioa. In addition, exploration drilling of the Sidewinder field in Block 6 will be done in 2012/13, with net P50 reserves of 46 mmboe with a potential upside of 96 mmboe. Tullow´s interest in commercial and contingent net P50 resources amounts to over 400 mmboe, where only 3 mmboe are commercial (producing). The assets in Mauritania can become important for Tullow going forward with large areas of unexplored geology.

2.2.3.5 Equatorial Guinea

Figure 2.10 Equatorial Guinea

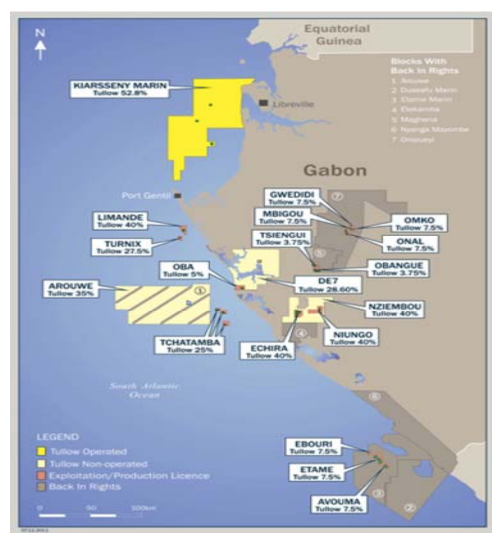


Tullow operates two producing fields in Equatorial Guinea, the Ceiba and Okume Complex. The production averaged 2.837 bopd in Ceiba and 10.214 bopd in the Okume Complex in 2011 net to Tullow, which accounts for 17% of the group´s total production. The net commercial P50 reserves are estimated to 26 mmbo.

During last year, seismic data was acquired in both the fields to determine locations of future production wells. In 2011 Tullow proceeded a thorough drilling programme on the Okume block and a tie-back of a satellite discovery well[69] on the Okume field. The tieback was delayed in 2011, resulting in a decreasing production compared to 2010.

2.2.3.6 Gabon

Figure 2.11 Gabon



Tullow has interest in 13 fields (operator in one) in Gabon, with an average net production of 12.700 bopd in 2011, or 16% of group's total production. Throughout 2011, 120 new appraisal and infill wells were drilled and completed, resulting in sustained production, and an increase

69 Satellite fields: smaller subsea fields to be tied back to existing platform.

in gross reserves of 351%[70], which is very good for such a mature area.

Their commercial and contingent P50 net levels are 52 mmboe, and the exploration drilling which includes the Kiarsseny field has net P50 of approximately 20 mmboe with a potential upside of 45mmboe. This year, Tullow and its partners plan to drill about the same amount of wells as in 2011. Gabon is an important asset for Tullow due to its steady production, and therefore reliable cash flow generator.

2.2.3.7 Congo (Brazzaville)

Figure 2.12 Congo

Tullow has onshore development and production interest in the M'Boundi oil field operated by Eni. In 2011 WI production averaged 3.000 bopd (4% of total production). The production was lower than expected due to issues with the water injection system in the second half of the year. These issues have now been resolved, and production volumes recovered in Q1 2012. The company has a net P50 of approximately 10 mmboe in the M´Boundi field.

2.2.4 West African Jubilee Play (WAP)

After the successful exploration and development of Jubilee and the adjacent TEN prospects, Tullow seeks to use their existing knowledge in similar prospects in the Equatorial Atlantic Region. They are trying to discover twin basins to Jubilee in West Africa and North East Latin America, as illustrated in Figure 2.13. The West African Jubilee Play (WAP) is therefore an important milestone in Tullow´s strategy, and the reason why they have built a strong presence in the relevant countries. The countries included in the WAP are Mauritania, Senegal, Sierra Leone, Liberia, Ivory Coast, Guyana, French Guiana and Suriname where similar basins have been identified either through seismic data or exploration drilling. Figure 2.13 gives an overview of the Equatorial Atlantic (West African "Jubilee" Play).

70 Tullow: Full year result – *p.8*

Figure 2.13 West African Jubilee Play

Source: www.tullowoil.com, About us

The first successful test was the Zaedyus fan discovery in 2011, which further de-risked the South American assets. In addition, the Jaguar prospect in Guyana, Mercury and Jupiter in Sierra Leone, Montserrado in Liberia and Kosrou & Paon in Ivory Coast are prospects with similar fan structures as Jubilee and Zaedyus. These countries within Equatorial Atlantic will form part of Tullow´s high-impact exploration drilling in 2012 and 2013. The characteristics of these formations are that they belong to the stratigraphic traps group[71], and not to the normal structural traps[72]. Stratigraphic traps are more difficult to spot on seismic data and to pinpoint the actual structure, but Tullow has shown that they are able to do so with both the Ghanaian and the South American assets[73].

It is difficult to locate these fan systems in existing basins, because the basins are often separated. This demands a high level of geological knowledge in addition to relevant experience in similar geological structure. Tullow showed that they are able to interpret the 3D seismic with the Zaedyus prospect, where the drilling results so to say matched their prognosis. Therefore, in a world where E&P companies´ ability to target and develop stratigraphic traps is seen on as onerous, Tullow has developed an edge, which is why WAP is such an important strategic milestone. Any company today can buy software that interprets seismic data, but in the end, it is the skill-set of the geologists that determine the success, and Tullow has succeeded where others have failed. After the Zaedyus discovery,

71 See Appendix 10 – Stratigraphic and structural traps

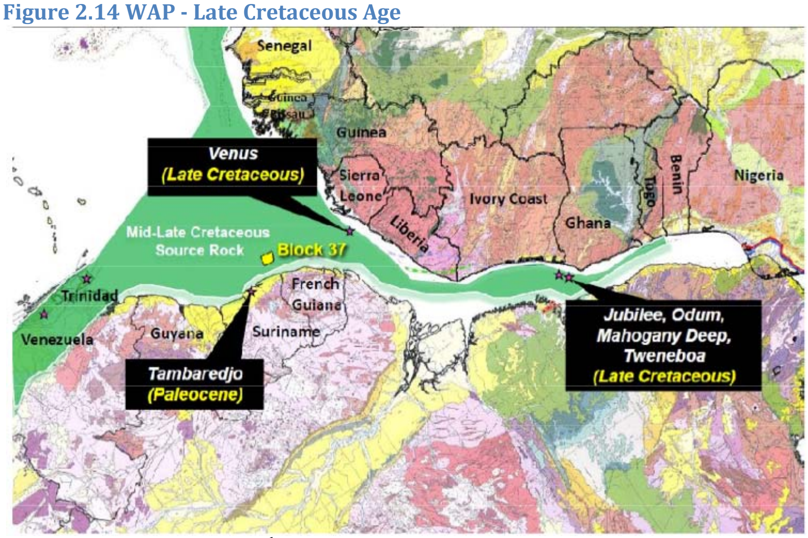
72 Bernstein Research: Tullow: Birth of a Super-E&P – *p.6*

73 See appendix 11 for visualization of "sub-marine" fan similar to the Zaedyus prospect.

Tullow´s exploration director commented; "*The result marks the start of a significant and potentially transformational long-term exploration and appraisal campaign in the region*"[74].

Tullow´s argumentation concerning South America as part of the WAP is due to the historical connection between Africa and South America as seen in Figure 2.14. Scientists have argued for years that the geological conditions in the northern part of South America are similar to the ones in West Africa, and this is what Tullow has worked on following the Jubilee success in Ghana. The explanation of the theory is highly technical, but easily said, the two continents that once were close together have through millions of years drifted apart, creating different geological layers and fan structures such as in Jubilee and Zaedyus. The green part of the figure represents excellent upper Cretaceous marine rocks, which under the right circumstances turn into "source rock" for oil and gas. Source rock refers to the rocks from which hydrocarbons have been generated or are capable of being generated. In other words, they form one of the important elements of a working petroleum system.

Figure 2.14 WAP - Late Cretaceous Age



Source: Bernstein Jan. 17th 2011 p. 3

The prospects in the WAP countries where sub-marine fan structures are found in seismic data have been de-risked through successful exploration drilling in Ghana, but even more with Tullow´s discovery in French Guinea. The prospect drilled in French Guinea is the first prospect in a fan system of 7 other similar sized leads nearby, all with a similar structure as Jubilee, which can further increase total reserves.

WAP is important for the valuation, due to the massive size of the combined assets. It is not only important in terms of the financial part, but also in terms of the strategic view due to the fact that the WAP will be prioritised in the exploration programme going forward.

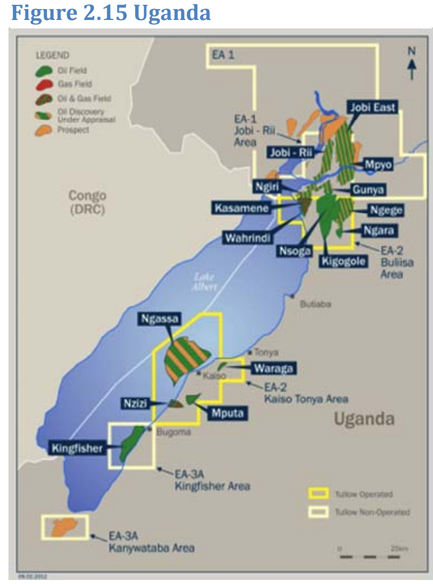
74 Bernstein Research: Tullow: Birth of a Super-E&P – *p.12: Quote from Tullow's Exploration Director*

2.2.5 South & East Africa[75]

Total production	Total Commercial & Contingent reserves	Sales revenue	2011 investment
0	540 mmboe	0	$418 million

2.2.5.1 Uganda

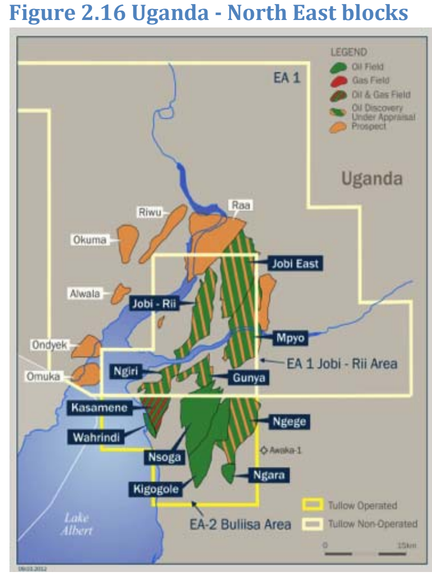
Figure 2.15 Uganda



In 2004, Tullow acquired Energy Africa and obtained their first interest in the Lake Albert Rift Basin in Uganda. Since then, 46 wells have been drilled with a success rate of almost 100%. Tullow also acquired Hardman Resources in 2007 and Heritage Oil & Gas Ltd´s interests in the area in 2010. Ultimo 2011 1,1 bnboe of P50 resources had been discovered and according to Tullow 1,5 bnboe of P50 prospective resources remains to be discovered[76].

<u>Acquisition and farm-down problems:</u> The takeover of Heritage´s interest in the Lake Albert area led to a one-year tax dispute between Tullow and the Ugandan government. Tullow acquired 50% in the exploration licences EA1 and EA3A (see Figure 2.15), for $1,45 billion in July 2010. $283 million were deposited due to an on-going dispute between Uganda and Heritage over unpaid tax.

Figure 2.16 Uganda - North East blocks



After the acquisition of Heritage's interests, Tullow started the planning of a farm-down in the Lake Albert area to start developing the field, and this required an approval from the government. A conditional approval was given in March 2011, where a resolution to the Heritage tax issue was provided. In May 2011, Tullow sued Heritage of $313 million due to this dispute[77], but no outcome has yet been finalized.

In extension to the conditional approval, a Memorandum of Understanding (MoU) was signed,

75 An overview over key statistics for the region can be found in appendix 8.

76 See appendix 2 for description of P10, 50 and 90.

77 The Telegraph Tullow sues Heritage over unpaid Ugandan tax bill

which enabled Tullow to proceed with its farm-down process. Due to several delays from the Ugandan Government, Tullow was not able to farm-down as planned during 2011. The farm-down of two thirds of Tullow's interests in Uganda with Total and CNOOC was finally approved in February 2012 for a consideration of $2,9 billion.

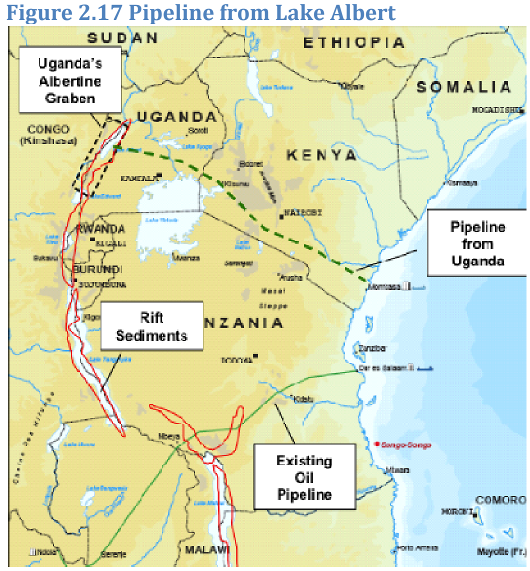
E&D activity going forward: Throughout 2011, several important discoveries were made in both EA-1 and EA-2, and successful appraisal wells extended the fields several kilometres. A large number of appraisal wells and well tests are also planned for 2012.

Development plans have been submitted for the fields Waraga, Mputa, Kasamene and Nzizi in block EA2. When the development plan is finished, a Front-End Engineering and Design plan (FEED) will be made. The FEED is part of the tenders sent out to the suppliers (drilling, seismic, infrastructure companies) so that Tullow can get qualified offers on the project.

The cooperation Tullow has established with CNOOC and Total is a strategic move. Total is one of the world´s largest IOC and CNOOC is China´s largest producer of crude oil and natural gas[78]. These three companies combined have the financial ability to finance the large amount of capex planned for the development of the area, and the companies will operate one block each. Their short term plan is to use five rigs in the basin, focusing first on Block 1 (EA1, Jobi-East and Mpyo) operated by Total.

Development challenges: As illustrated in Figure 2.17, the country is about 1.300 kilometres from the coast, and Tullow needs to create an international export channel from Lake Albert to the coast. Their plan is to build a pipeline through Uganda and Kenya with a final destination of Mombasa where the oil will be exported. This will be involving both political as well as economical risks. It is also important that the pipeline is able to handle future production from the newly discovered prospects in Kenya. In addition they plan to

Figure 2.17 Pipeline from Lake Albert



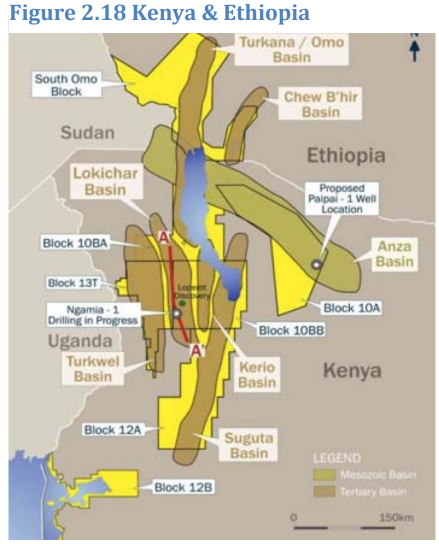
78 CNOOC: About Us

build a refinery near Lake Albert so the oil can be sold to the local market and nearby countries. Tullow expects to get government approval in 2013 with start up of pipeline in 2016[79]. The estimated capex for the development is \$5,5bn[80].

Some small scale production will commence ultimo 2012, but substantial production will commence approximately three years after the government's approval (2015/2016) of the basin development. The drilling done in 2011 has given strong indication of further exploration upside, and combined with previous findings this supports the future development plans of the area. The drilling programme in 2012 involves net P50 levels of 185 mmboe with a potential upside of 400 mmboe, and potential E&A drilling targets for the 2013 program is currently being analyzed. Tullow expects the basin to excess 200.000 bopd at plateau production.

2.2.5.2 *Kenya and Ethiopia*

Figure 2.18 Kenya & Ethiopia



Tullow operates a 50% interest in seven different basins in Kenya (5 basins) and Ethiopia (2 basins). To date, 80 leads and prospects have been identified, and the number increases every week[81]. The company's acreage position covers 80.000 sq km and is aerially 14x the size of its acreage in Uganda. The acreage covers the Turkana Rift Basin, which has similar characteristics to the Lake Albert Rift Basin.

<u>*A new "Lake Albert" like basin?*</u> The Ngamia-1 exploration well in the Turkana County spudded on January 25th, and the company announced, on March 26th, that the well had encountered in excess of 208 metres of net oil pay[82]. \$1,5bn was added to Tullow's market capitalisation on the day the discovery was announced. The success at Ngamia have mitigated the integrity risk for nine similar-sized follow-up leads, and it is not inconceivable to think that 550 mmboe are possible for the Block 10BB alone[83]. The area is believed to have a total potential upside of 5x the size of

79 UBS: Feedback from roadshow with COO

80 Goodbody Stockbrokers: E&P Update April 2011

81 UBS: Feedback from roadshow with COO

82 Tullow: Press release: Ngamia-1 oil discovery in Kenya Rift Basin

83 Nomura: Ngamia and Kenya still drilling

Uganda[84]. The tax terms are also notably better in Kenya (60-70%) than in Uganda (70-80%), and the distance from sea is 2/3 of that in Uganda with no neighbouring countries with which to negotiate. The success in Ngamia demonstrates how prospective the region is as the prospect is not viewed on as one of the most attractive in the respective basins.

The Paipai-1 well in the Tullow operated Block 10A will spud in 2H 2012, but as this well is separated from the above mentioned prospects, it is no de-risking opportunities beyond the exploration well.

Only 18 mmboe are included as net P50 within the contingent resources from Kenya, but over 400 mmboe of net P50 are included in the exploration programme in 2012, with a potential upside of 590 mmboe.

2.2.5.3 Namibia

Through the acquisition of Energy Africa in 2004 Tullow acquired the Kudu gas field offshore Namibia. Tullow is the operator of the 4.567 sq km licence, and the development of the gas-to-power project is now making progress. An investment decision in 2H 2012 could mean the delivery of gas and power generation by 2H 2015. The company has net contingent P50 levels of approximately 155 mmboe in the country.

Figure 2.19 Namibia

2.2.5.4 Madagascar

Tullow has interests in both the onshore Mandabe licence and Berentu licence covering a total of 20.100 sq km. In 2011, over 450 sq km of 2D seismic data were acquired which successfully proved existence of light oil, and data is still being processed. A farm-out process is on the way with intention of reducing Tullow’s equity to 50%.

2.2.5.5 Tanzania

Tullow has interest in two onshore licences in the Tanzanian portion of the Ruvama Basin totalling 12.360 sq km. Tullow farmed down its interest from 50% to 25% to its partners in November 2011, and decided in March 2012 to withdraw from the Ntoyra-1 well

84 Bank of America Merrill Lynch: Kenya twice size of Uganda & potentially transformational.

that spudded on 22 December 2011 due to poor results. There is no further information regarding planned development of the area.

2.2.6 Europe, South America & Asia[85]

Total production	Total Commercial & Contingent reserves	Sales revenue	2011 investment
20.800 boepd	133 mmboe	$360 million	$246 million

2.2.6.1 Europe

Tullow's gas production assets in both the UK and the Netherlands provide valuable cash flow to the company. The assets in the two countries are mature, with no immediate potential upside but tieback opportunities are being developed to maintain the current production.

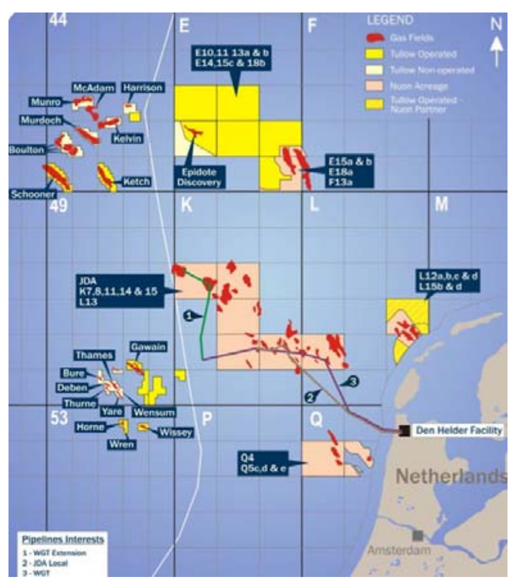
2.2.6.1.1 UK

Tullow entered UK Southern North Sea through the acquisition of producing gas fields and related infrastructure from BP early in 2000. In 2011 WI production averaged 12.500 boepd from 16 fields representing 16% of Tullow´s total production. The Thames area averaged 1.000 boepd while the CMS Area averaged 11.500 boepd. Infill drilling has been done, and production levels are to be stable going forward. There is a total net P50 of 44 mmboe in the 16 fields divided between the two areas, and an overview map can be seen in appendix 12.

2.2.6.1.2 The Netherlands

Tullow acquired the first two licences offshore The Netherlands in 2007. Again in May 2011, the company acquired Nuon Exploration & Production from the Vattenfall Group for a consideration of $378 m. The acquisition included 25 licences over 30 gas producing fields, with a net production in 2H 2011 exceeding 6.000 boepd. 29 new wells are planned in the Joint Development Area offshore the Netherlands in 2011 and 2013, which will

Figure 2.20 The Netherlands



85 An overview over key statistics for the region can be found in appendix 9.

extend the life of the field by 10 years and increase net production by 1.500 boepd. There is a net P50 of 42 mmboe in commercial and contingent resources, and on the exploration side, there are P50 levels of 11 mmboe with an upside potential of 17 mmboe that are expected to be drilled. Tullow has in addition acquired 51.174 sq km of 3D seismic data in the area from PGS to evaluate further regional exploration.

2.2.6.2 South America

Tullow has deepwater interests in French Guiana, Guyana and Suriname which is part of the West African Jubilee Play (WAP) as described in part 2.2.4. The area has a lot of similarities in terms of the geology with the West African area, which can indicate a future potential upside[86].

Figure 2.21 South American Assets

2.2.6.2.1 French Guiana

Tullow has interests in the Guyane Maritime offshore block, which is in the E&A phase. The company is operator with a WI of 27,5%, together with Total (25%) and Shell (45%). In September 2010, Shell exercised its right to increase its interests after Tullow´s farm-down in 2009 which is a positive signal for potential reservoirs regarding this high-risk area. Analysts call it the next possible Jubilee field and the seismic data has supported this theory[87]. In September

Figure 2.22 French Guiana

86 See part 2.2.4 - West African Jubilee Play (WAP) for a more detailed explanation.

87 Bernstein Research: Tullow, Shell & Total: 2011 Frontier Exploration in French Guiana

2011 the Zaedyus-1 exploration well made a significant discovery of 72 metres of net oil pay in two turbidity fans[88], which is the first out of another 7 similar prospects in the fan structure.

The appraisal tests will commence in late June 2012, and the Dasypus-1 exploration well will spud in 4Q12. The net potential upside in the Dasypus prospect is estimated to 140 mmboe with a P50 of 63 mmboe. The 2012 programme also includes large 3D seismic surveys over the Saguinus & Samiri Channels[89] and the Cebus fan system to further establish new potential exploration wells. The Zaedyus prospect has net P50 contingent levels of 48 mmboe at present, and the total exploration P50 levels are 121 mmboe with an upside potential of 231 mmboe.

2.2.6.2.2 Guyana

Figure 2.23 Guyana

The Georgetown Block where Tullow has 30% WI is in an early E&A phase where seismic data has identified potential prospects. Exploration drilling on the Jaguar prospect was delayed primo 2012 due to operational and weather problems on wells drilled by other parties in Suriname, which resulted in the rig not arriving on location in time. The well commenced drilling in February 2012 and is expected to finish in Q3 2012. There are uncertainties to whether the Jaguar prospect is a single prospect or a fan system as the seismic quality is not the same as over the Zaedyus fan system. It will thus take more than just one well to de-risk the Jaguar fan system[90], but the current seismic data supports their theory concerning WAP. The estimated net exploration P50 reserve base is 129 mmboe with an upside potential of 354 mmboe.

2.2.6.2.3 Suriname

Tullow signed a PSA (40% WI) in 2007 with, among others, Suriname´s State Oil Company regarding the onshore exploration block Coronie. The block lies adjacent to

88 See appendix 11 – Zaedyus fan structure

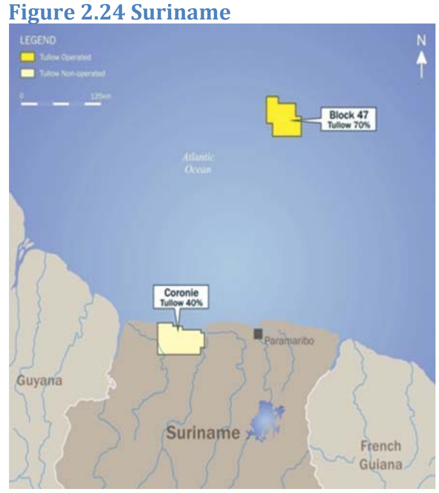
89 See appendix 13 – Guyane Maritime Cross Section

90 Credit Suisse: Tullow; Still evolving – *p.9*

Suriname´s main heavy oil producing field, indicating that the blocks may hold similar reserves. Current net exploration P50 is 40 mmboe with a potential upside of 100 mmboe.

In September 2010, Tullow signed another PSA with the state, regarding Block 47, as an exploration play to establish a field similar to the Jubilee field. In 2011 they finalised the farm-down of a 30% interest in block 47 to Statoil, leaving Tullow with 70% WI. They are planning a large seismic programme of over 2.500 square km, with scheduled start in Q2 2012.

Figure 2.24 Suriname



2.2.6.2.4 Asia

Tullow took the decision in March 2012 to commence a process to sell all Asian assets. Therefore, the values are not included in the model, or the description.

2.2.7 Summary

As described, Tullow has an extensive asset base with operations in more than 20 countries and production in 10. Their largest discovery to date set into production is the Jubilee field offshore Ghana with total P50 commercial reserves of 700 mmboe, and an expected combined production from the area of 120.000 bopd going forward. When plateau production is reached, the field will become an important source of revenue to fund for future exploration and development programmes. The Lake Albert Rift Basin in Uganda is another of Tullow’s most important assets with P50 reserves of 1,1 bnboe ultimo 2011. Tullow completed a $2,9bn farm-down to CNOOC and Total in 2012, and the three companies now own 1/3 of the field each. The partners are working with the Government of Uganda to clearly define the future development of the field. With many of the similar characteristics as the Lake Albert Rift Basin, the prospective East African Rift Acreage in Kenya represents the latest discovery for Tullow, with high potential upside. The first exploration well in the area discovered oil in March 2012, and analysts’ estimates that the potential upside in the area is could be up to 5x the Lake Albert Rift Basin reserves.

In the longer term, another potential catalyst for Tullow is the countries in the West African Jubilee Play (WAP). The theory is that as the two continents, Africa and South America, once were close together, and twin basins to the Jubilee field could exist in the adjacent countries. Seismic surveys supports the theory and exploration drilling could further de-risk the area in the years to come.

2.3 SWOT

The most important strategic parameters have been classified into a SWOT model, where the level of competitive advantages/disadvantages is measured. Each parameter is quantified against industry average, where industry average is set to 1, on a scale of 1 – 4. The ranking of strengths and opportunities are based on Tullow´s competitive advantages where a rank of 4 is the best, while weaknesses and threats are based on their competitive disadvantages where a rank of 4 is the worst. The different parameters are used in the subjective estimations throughout the NAV model.

Figure 2.25 Strengths

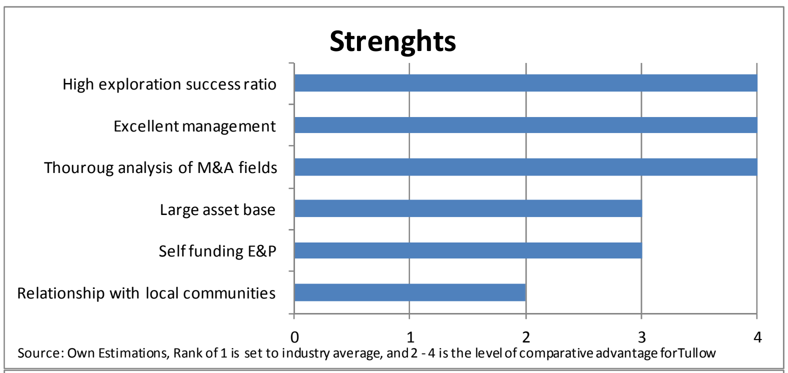


Figure 2.26 Weaknesses

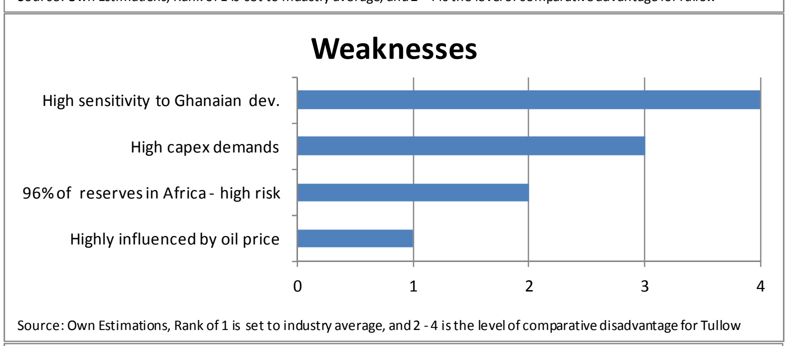


Figure 2.27 Opportunities

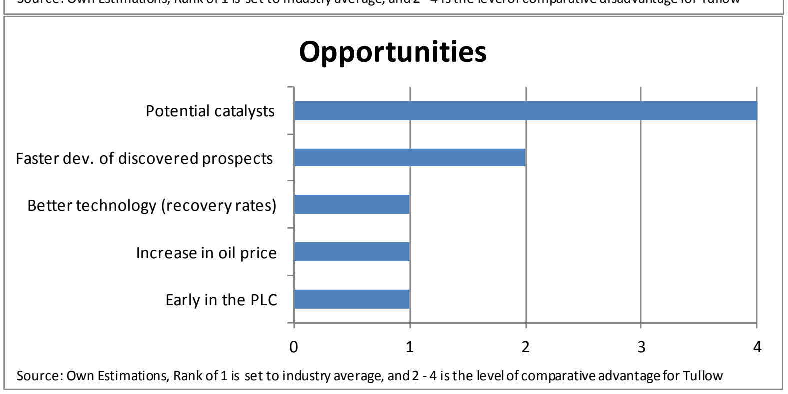
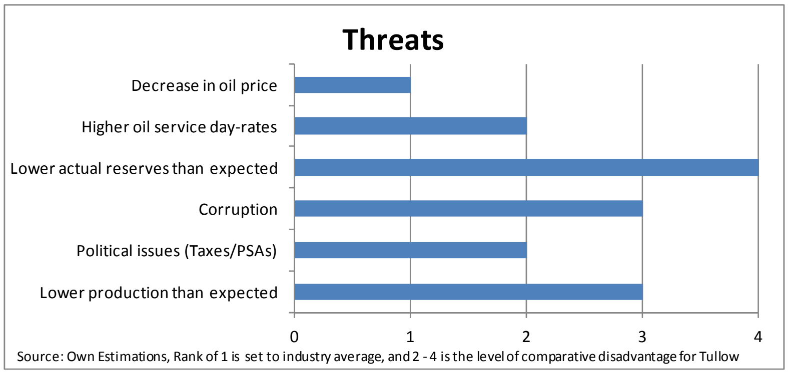


Figure 2.28 Threats



3 NAV model

In the following sections the fundamental of the NAV model and the forecasting assumptions will first be explained in general before the assumptions made in the specific countries are elaborated.

3.1 NAV model fundamentals

When looking at a company with an asset base that is difficult to value, it is more reliable to use a Net Asset Value (NAV) model than a common DCF-model. The NAV model includes all assets associated with the company. For an E&P company like Tullow, the assets are their licences, with an estimated reserve base within each license. Estimating the risk weighting within each field requires a good insight into the company and an understanding of the geological environment.

Each field´s P50 levels are accounted for in the model, as well as the different PSCs or tax regulations within each country. The advantage of the NAV model is that it gives a good overview of the value of the company´s assets, and what part of the value that comes from exploration opportunity and ordinary production.

The different areas of present- and future potential production have been forecasted with individual DCF models (Ghana, Uganda and so on). The forecasting includes the expected opex, capex, PSC details, tax rates, working interest and other calculations necessary to calculate the EV/bbl. The NAV model divides Tullow´s assets into three categories, Commercial NAV, Contingent NAV and Exploration NAV.

Commercial NAV includes the assets that are currently in production, or in a development phase to be tied-back to existing production. The commercial NAV is not de-risked by any risk weight because it is part of a planned production (Risk weighing 100%).

The only de-risking in this part of the NAV model is the chosen amount of the P50 reserves guided by Tullow.

Contingent NAV covers the areas where the discoveries are made, but where there are a lot of uncertainties in terms of future development. Examples of future risks could be low volume, low valued gas or problems in terms of production set up. The company must decide whether, and how, to start production or if the field should be abandoned. Contingent fields are therefore being de-risked with a factor between 35 – 80%.

Exploration NAV is where the most uncertain fields are valued. This includes production from the different fields assumed to begin after 2015, or potential upside from current fields in production. It also includes areas where there has been done non-exploration drilling, only analysis of processed seismic data. The basis for the exploration NAV is the 12 month exploration program presented in Tullow's Fact Book 2011. The risk weighting is between 10 – 50%.

3.2 Output description

The reason why E&P companies can be difficult to value is the complex combination of assets, where the value of each asset can be challenging to determine. As described earlier, each field is measured with a P10, P50 and P90 probability that indicate the amount of oil equivalents in the reservoir.

Table 3.1 Definitions of Reservoir Classification

P90 1P	P50 2P	P10 3P
Proven	Proven Probable	Proven Probable Possible

P90 means that it is a 90% probability that the level of oil in the reservoir is X amount or higher, and similar with the P50 and P10 which represent 50% and 10% probability that the level is X or higher. The P10 values are of course larger than the P90 values, but also with a smaller probability. The value of a field is therefore a question of subjectivity, which provides a high level of volatility for the public traded companies. It is to be said that Tullow has an almost perfect correlation with the oil price, and this relationship will be further elaborated in part 3.3.1.1.

If a normal DCF model were to be used in the case of Tullow, with 100+ licenses, it would have been difficult to project the cash flow without looking into each area of operation, and take each of the areas circumstances into account. One field A can have larger proven levels of oil equivalents than field B, but field B can be more worth than field A if for example field A is on a greater depth or more complicated to extract the oil from. Due to this, a Net Asset Value model will be used as the main valuation tool, where each area of production will be analysed and the approximate enterprise value per barrel produced in the different areas will be calculated using a DCF model. In this way further risk adjustment can be done for the different licenses within the area, and an overview of the values from today's estimated levels of oil can be made.

There is also a difference between the asset classes owned by Tullow. Tullow operates a self-funding E&P model as described, where "safer" assets fund assets with a higher risk profile. The gas fields in UK and the Netherlands are examples of the safer assets, and on the other side, the assets in Africa are characterized as more uncertain fields. In this thesis, the main focus will be on the uncertain fields because this is where the potential upside lies. The safer assets will be valued in an "easier" way, or more standardized based on the information provided by the company.

Figure 3.1 NAV output description part one

Net Asset Value (NAV)		Spud date	P50 gross resources	P50 working interest	P50 entitled reserves	EV/bbl working interest	EV/bbl entitled
Country	Field		mmboe	mmboe	mmboe	$/boe	$/boe

The figure above shows the first part of the output, and each of the different components will be described below.

<u>Spud date</u> is *"Spudding: The initial drilling of a well where the top layer of the rock is entered"*[91]. This is in other words when the company starts to drill in the license, and is therefore an important date. The sooner the company can start producing, the more value the field has today due to the time value of money. This information, along with the other information concerning the different fields, is provided in Tullow's Fact Book.

<u>*P50 gross resources*</u> are the overall remaining levels of oil in the field, without taking Tullow's working interest into account. P50 is used as a mean value because the P10 will be too optimistic and P90 to pessimistic.

91 HSBC: European Oil Service – *p.*139

P50 working interest values are the net value to Tullow. The working interest level may vary significantly from field to field, due to the cooperation between different companies in the development and production of the fields. Tullow also provides these levels.

Entitlement factor describes how much of the working interest levels that the company is entitled to. This may be due to specific fees or regulations from the government in the specific country, with different Production Sharing Contracts (PSC) where fees have to be paid to the respective government at certain levels of production. In this way the negative cash flow to the respective government is proportional to the amount of oil produced.

EV/bbl working interest is Tullow's share of the enterprise value per barrel of one license within an area, calculated with help of a DCF model. The value calculated is not subtracted any debt, and is therefore the enterprise value. This is the un-risked value, where P50 levels are assumed valid. The amount is divided with the total amount of barrels that is net to Tullow according to the working interest in the specific field. The EV/bbl multiple is therefore a measure of the value per barrel that is produced with the time value of money taken into account. An example with two identical fields, where A is planned to start production year 1 and B will start in year 10 can explain this. The EV/barrel will be higher for field A because of fewer discounting periods, and as a result, the field has a higher value than field B. The EV/bbl entitled is exactly the same, but with the entitled amount as the denominator.

Figure 3.2 NAV output description part two

Risk weight-ing	Unrisk ed EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Entitle ment factor	Field WI (eq)	Currency
%	$m	$m	p/sh	%	p/sh	p/sh	%	%	%	£/$

Risk weighting assigns each field with a given percentage risk factor to adjust the present value of a prospect, based on P50 values, for uncertainties within the field. This is where the characterization Commercial, Contingent and Exploration NAV are used as described above. If a field has a risk weighting of 60%, than 60% of the present value is accounted for in the overall risked NAV value. The risk weighting is of course subjective, and is a key input in the NAV model that makes it vulnerable for errors.

Un-risked Enterprise Value is the DCF value for the fields, if this is calculated. For fields where a DCF model is not made, the EV/bbl from a similar nearby field is used. The un-risked EV is calculated by multiplying the EV/bbl WI from the associated field with the WI amount of oil equivalents for the respective field. This can be illustrated with an area A, with the fields A1, A2 and A3. A DCF model can be made for A1, and used to approximate the value of A2 and A3 by using the same EV/bbl WI as A1, but a different risk weighting.

Risked EV is simply the un-risked EV multiplied with the risk weighting. If a field has a risk weighting of 50%, the NAV model only accounts for 50% of the assumed value in the field and so on. These two measurements will, for the commercial NAV, be equal due to a risk weighting of 100%. The risked measurements are showed both in USD and GBP, as Tullow is listed in UK, but the oil industry uses USD.

The rest of the multiples are purely mathematics;

- Risked EV/share = Risked EV divided with number of shares
- % of group value = Risked EV/share divided with total NAV value
- Un-risked EV/share = Un-risked EV divided with number of shares
- NAV upside = Un-risked EV/share subtracted risked EV
- % NAV upside = NAV upside divided with total NAV value
- Entitlement factor = published by Tullow
- Working interest = Tullow’s share in the respective field

By completing a NAV model, and work through each license, a thorough analysis of Tullow can be made. In this way the value from the different areas of operations can be separated to understand what drives the share-price.

3.2.1 Input factors

In a complex company like Tullow, where operation stretches from South America to Europe, it is clear that factors such as operational costs, capital expenditures, logistics, working interest, reservoir levels, taxes and fees may vary a great deal. For this purpose, Tullow regularly publishes a Fact Book where key information is presented. In addition, actual and forecasted (1 year) capital expenditures are given, divided into the main area of operation. This means that all the information necessary to calculate the NAV value is provided, except from key elements as the risk weighting, discount factor and production forecast. The part 3.3 – Forecasting, the overall assumptions are explained and in part 3.3.4 – Modelling Essential Fields, the specific country details are presented.

3.3 Forecasting

In this part essential forecasting assumptions will be explained. There are two main input factors that determine the revenue, the oil price and the gas price. Both of these factors are a function of supply and demand of oil and gas.

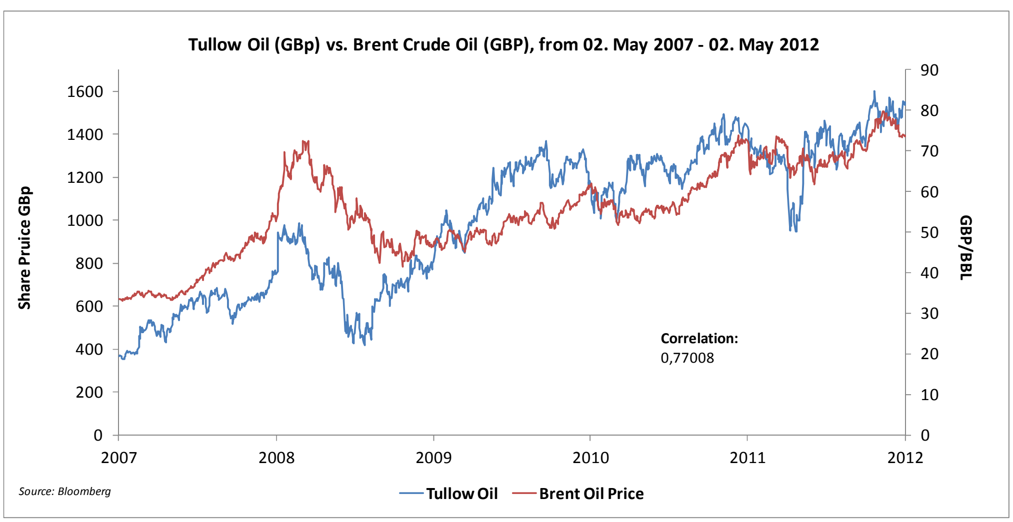
3.3.1 Market Driven Input Factors

3.3.1.1 Oil Price

In general E&P companies have a close positive correlation with the oil price because of their role as a price taker, and an investment in such a company is often a pure play on the oil price. As seen in Figure 3.3, Tullow does also have a clear positive correlation with the oil price, which means that a decreasing oil price will have a negative impact on Tullow's earnings and cash flow, and vice versa. During the financial crises, the whole market fell drastically as a result of a decrease in the oil price, and Tullow´s share price also dropped substantially. However, after the financial crisis, Tullow clearly outperformed the oil price due to stronger fundamental signals from the company. This can be interpreted as the market starting to give Tullow acknowledgement for their asset base, and Tullow went from being a pure play on the oil price, to also being a play on their operational quality and asset base development.

Figure 3.3 shows the correlation between Tullow´s share price and Brent Crude Oil, converted from USD to GBP.

Figure 3.3 Tullow Oil Share-price vs. Brent Oil Price development (2007 -2012)



Because of the high correlation with the oil price, the basic factors that determine it will be analyzed below.

US dollar exchange rate: The oil price has an inverse relationship with the US dollar exchange rate, as all oil is traded in US dollars. All other things being equal, when USD weakens the oil price will strengthen and vice versa.

Supply and demand: The fundamentals of supply and demand are the most significant factors. Demand typically does not fluctuate too much, except in the case of recession, but negative supply shocks[92] can occur when large oil producing countries are expected to decrease their production in short/mid-term perspective, due to for example political instability.

Expectations to future oil price: During the summer of 2011, the economic situation in Europe became unstable due to uncertainty linked to the Southern European countries´ ability to handle their debt, and their general economic state after the effects of the financial crisis during 2008-2009. This had a severe effect on the financial markets, which led to a decline in equity prices, especially within the Energy sector. Fear of further economic downturn in Europe lowered the long term economic expectations, which accordingly led to lower expectations for the oil price. Tullow was one of the companies that suffered for this and fell almost 30% during July and August 2011[93]. The oil price did not react as drastically (approximately –14%), but this was mainly due to the situation in the African oil producing countries where the political situation was very unstable, and a fear for further expansion to other nearby oil producing countries was present. This kept the oil price level high despite the European debt shock. Therefore, when the oil price did not decline as many expected, the share price bounced back to "normal" levels as seen in Figure 3.3.

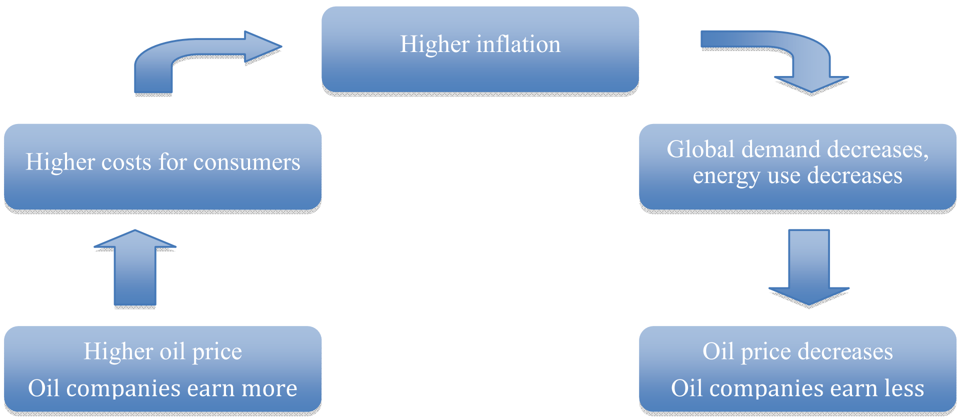
Sustainability of oil price: In addition to the above, it is said that the world does not gain on oil price levels above $100. At higher levels the oil companies will make more money in the short term, but in the long-term aspect the rest of the economy will suffer. The reason for this is that the rest of the economy will have higher costs due to a high oil price, which will generate an increasing inflation and in the end may affect the general consumer negatively. If this happens, the global demand may fall, which again will affect the global growth in the economy, consumer consumption and energy use. This kind of "bubble" is not

92 Negative supply shocks means a sudden decrease in supply, leading to higher oil prices.

93 Source: Bloomberg

in the oil companies´ interest, nor for the rest of the economy, and the fundamentals therefore support a lower long-term oil price than today´s price. Figure 3.4 illustrates how a too high oil price neither is good for the economy as a whole, nor for the oil companies in the long term.

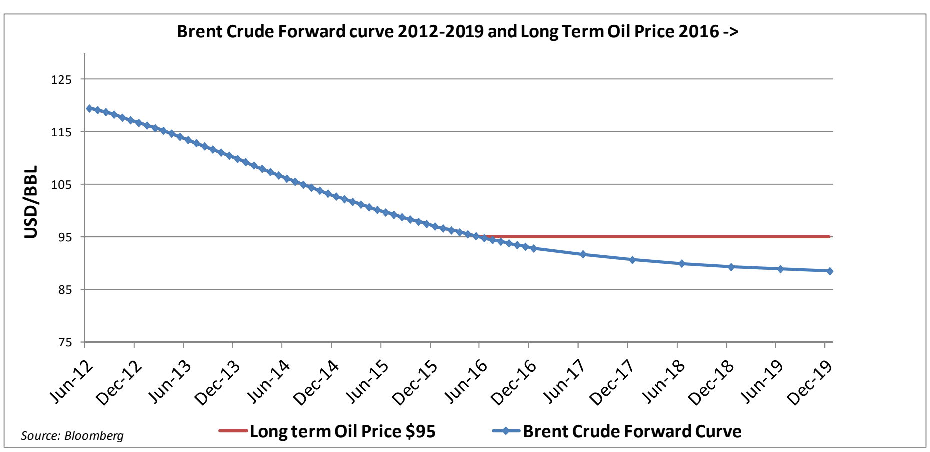
Figure 3.4 Consequences from higher oil price



Oil as a financial asset: Another factor that might create fluctuations in the oil price is that oil is being viewed as a financial asset. This has led to an increasing level of involvement by financial market participants and, consequently, to a more volatile oil price[94]. These fluctuations are considered short-term and are assumed not to have any significant effect on the oil price in the long run.

Due to the complexity of the oil price, and the many factors that influence it, forward rates will be used as oil price forecast. In this way the valuation will be based on today´s current market view. The Forward curve per 30/04-2012 is shown in Figure 3.5.

Figure 3.5 Brent Crude Forward Contracts 2012 – 2019, April 30th



94 Deutsche Bank: Oil and gas for beginners (2010) *p.122*

As seen, the oil price is expected to decrease to \$85 – \$95 looking beyond 2015. This is of course an uncertain assumption, and a lot of things can change this curve, but it reflects today´s market view and is also taking the above mentioned factors into account. By calculating the average yearly prices we find our oil price estimate until 2019.

Table 3.2 Oil Price Assumptions in NAV model

Crude Brent Oil Price	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E
Average Forward Price USD/BBL	118,2	113,1	105,9	99,5	94,7	91,2	89,6	88,7
Used Price in NAV model USD/BBL	118,2	113,1	105,9	99,5	94,7	95,0	95,0	95,0

Source: Bloomberg

Table 3.2 shows the forward prices until 2019, and the second row shows the used prices in the NAV model. A long-term oil price of \$95/BBL is assumed from 2017 going forward which is the consensus long-term oil price among analysts. Bloomberg consensus prices seen in Table 3.3 show that the analysts are more optimistic of short-time prices, than the forward prices. In the valuation, market prices will be used.

Table 3.3 Average Analyst Expectation

Crude Brent Oil Price	2012E	2013E	2014E	2015E
Average Analyst Expectation	112,4	113,8	112,1	114,9

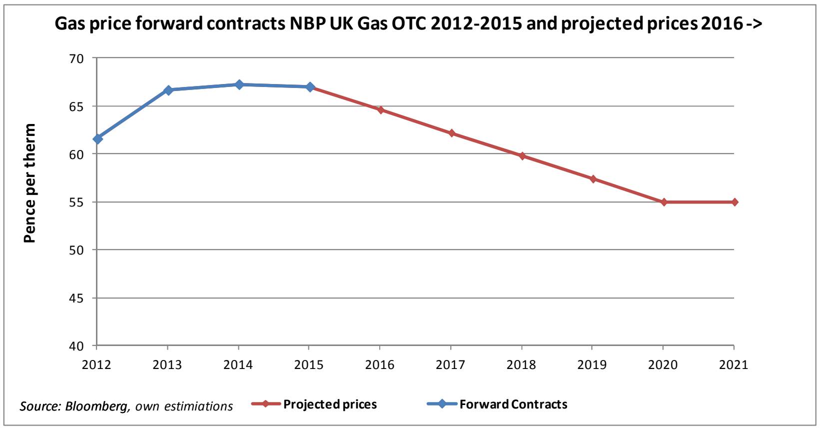
Source: Bloomberg

3.3.1.2 Gas Price

With a gas production of approximately 20 kboed in 2011, UK and The Netherlands represents ~30% of Tullow´s total production. The share of gas production relative to the total production is expected to decrease, which means that the gas price will be less important for Tullow in the future.

To project the future gas prices the National Balancing Point (NBP) contracts from 2012 to 2015 are used. NBP is a virtual trading platform for gas, and the price is measured in pence per term. There are no contracts looking beyond 2015, but a long term gas price of 55 is assumed from 2020, and the price is expected to fade to this level between 2015 and 2020.

Figure 3.6 NBP UK Gas 2012 - 2015 and projected prices 2016 and forward, April 30th



The natural gas prices have fluctuated a lot the last years due to the uncertainties concerning Liquid Natural Gas´ (LNG) affection on the overall supply side. A somewhat conservative view is therefore applied with a long term gas price of 55 pence per therm from 2020 and forward.

Table 3.4 Gas Prices Used in NAV Model

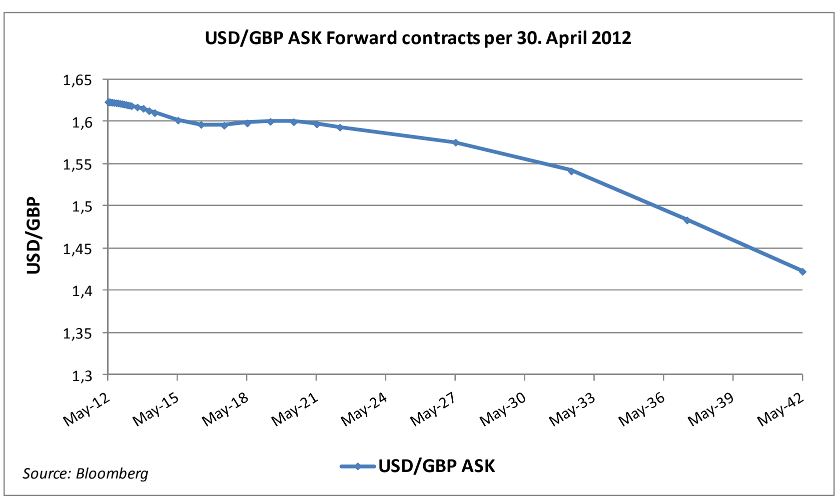
Gas Forward Price NBP UK GAS	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E
Average Forward Price p/therm	61,6	66,7	67,3	67,0	64,6	62,2	59,8	57,4	55,0	55,0

Source: Bloomberg

3.3.1.3 FX Rate

The foreign exchange rate between US dollars and British pounds is important in calculating fair value of Tullow, as the revenues are in dollar and the share price in pence. The exposure towards the exchange rate is somewhat mitigated by the strong relationship between the USD exchange rate and the oil price. (If the USD weakens, the oil price tends to strengthen and vice versa). The forward curve is used to project the exchange rates.

Figure 3.7USD/GBP Ask Forward Contracts, 2012 – 2042, April 30th



Yearly forward prices are disclosed ten years ahead, while from 2022 and forward are stated on a five-year basis. For the years in between the five years interval, the price difference is subtracted from the last given forward price to provide a smooth price curve. From 2042, the exchange rate is set to 1,42 USD/GBP, or the same value as in 2042. Table 3.5 shows the estimates until 2022.

Table 3.5 Average Forward Prices USD/GBP 2012 – 2022

USD/GBP	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Average Forward Price USD/GBP	1,623	1,619	1,612	1,602	1,597	1,596	1,598	1,600	1,600	1,597	1,594

Source: Bloomberg

3.3.1.4 Taxation/PSC

Every country with oil production has its own fiscal regime in terms of taxation for oil producing companies. The taxation system is designed to adjust relatively to the amount of oil produced. This system is called a Production Sharing Contract (PSC), where either the royalty rate or the government´s "share" of the oil revenue is determined by the amount of barrel produced per day in a progressive tax system[95]. Table 3.6 shows an overview of the different taxation regimes relevant to Tullow.

Table 3.6 Taxation Overview in Counties were Tullow is present

Taxation overview - Tullow Oil			
Country	**Regime**	**Taxation Rate**	**Royalty Rate**
Ivory Coast	PSC		
Equatorial Guinea	PSC	20,0%	11,0%
Gabon	Various		10,0%
Congo	PSC		12,0%
Mauritania	PSC	25,0%	
UK	Corp. Tax	62,0%	
The Netherlands	Corp. Tax	50,0%	25,5% CIT
Ghana	Corp. Tax	35,0%	5% Roy/APT 25%
Uganda	PSC	30,0%	Various
Namibia	Corp. Tax	35%	12,5%
Sierra Leone	Corp. Tax	30%	6,5%
French Guiana	Corp. Tax	40%	12,5%
Suriname	PSC	36%	6%
Guyana	PSC		
Liberia	PSC		

Source; Tullow Oil, Licence contracts PSC = Production Sharing Contract
CIT = Corporate Income Tax APT = Additional Profit Tax

As seen, PSC's are the most commonly used method to tax the oil producing companies because of its relative relation with the amount of oil produced. The terms for each contract vary a lot, and one country can have several different contracts depending on

95 Deutsche Bank: Oil and gas for beginners (2010) *p.108*

size and complexity of the field. The different PSC's used in the NAV model are found in Tullow's Fact Book, and various analysis. As an example, the PSC from the Espoir field in the Ivory Coast can be seen in Table 3.7.

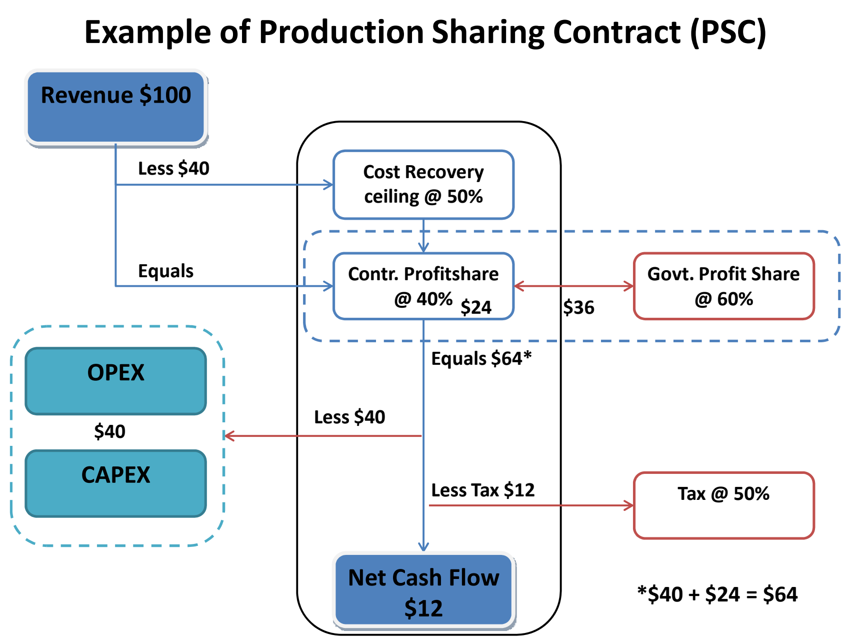
Table 3.7 Production Sharing Contract Ivory Coast

PSC - Oil Production			
		Production	Contractor Share
kboe/d	<	10	49%
kboe/d	<	20	47%
kboe/d	<	30	42%
kboe/d	>	30	37%

Source: Company Data Ivory Coast, NAV Model

The production levels per day determine the "contractor share", which is descending along with increased production. At 20 kboed for example, the contractors will receive 47% of the "Profit available", and the remaining profit is paid to the government. The government take may seem high, but the amount to be shared is subtracted the refundable capex and some operational costs. These are costs associated with exploration, appraisal and development of the different fields. Some of these costs are refundable if the field starts producing, and of course with a limit which is set as a percentage of gross revenue. This means that contractor´s revenue is added these costs (the revenue increases) due to the payback from the government. The recoverable costs are a standardized percentage of gross revenue in the NAV model, because it is too complicated to calculate it for every country. The calculation of the Net Cash Flow is done as follows.

Figure 3.8 Example of Production Sharing Contract



Source; Deutsche Bank, Oil and Gas for beginners 2010, p. 113. The numbers above are picked for illustration only

Figure 3.8 illustrates how $100 in revenue is split between government takes and associated costs. All the inputs vary from country to country, and from field to field. There are many different agreements and terms among the countries operated in, but they are meant to make payable taxes reflect the capital investments and the maturity of the producing field.

An example of the calculation in Ivory Coast is shown in Table 3.8, where contractor revenues of $328m in 2012 consist of contractor's share of $239m and Recovered costs inclusive capex of $90m (rounded numbers). It can also be seen that the contractors share changes from 47% to 42% due to increased production, and that there are no payable taxes in Ivory Coast beyond the PSC.

In the NAV model the recovered costs are a function of gross revenue and standardized with descending values, except from key fields such as Ghana fields where the levels have been more accurately calculated based on the license agreements with the Ghanaian government.

Table 3.8 Example of Net Cash Flow Calculation

Example of Net Cash flow calculation							
Revenue calculation			**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Gas revenue			57	115	115	86	57
Oil revenue			448	586	621	621	621
Gross Revenue		$m	**506**	**701**	**736**	**707**	**678**
Recoverd Costs inc Capex		$m	-76	-70	-74	-35	-34
Profit Oil available		$m	430	631	662	672	644
Contractors Share - A function of PSC		%	47%	42%	42%	42%	47%
Contractors Share		$m	202	265	278	282	303
Working interest			21%	21%	21%	21%	21%
Tullows share			**43**	**57**	**59**	**60**	**65**
Contractor take of cashflows			**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Contractor revenues including cost recovery		$m	278	335	352	317	337
Actual costs inc. Capex		$m	-262	-181	-175	-175	-145
Domestic Supply Obligation- payments	12,00%	$m	-31	-22	-21	-21	-17
Net contractor cashflow		$m	**-15**	**133**	**155**	**121**	**174**
Net Tullow cashflow		$m	**-3**	**28**	**33**	**26**	**37**

Source: Own calculations, NAV model and Tullow Oil

3.3.1.5 OPEX

Operational expenditures cover all the variable costs associated with the production, such as equipment, labour costs, logistics, maintenance and other direct costs. Information regarding opex the previous and present year is provided by Tullow in their Fact Book. Table 3.9 shows the estimated opex for the different countries up until 2016.

Table 3.9 OPEX in the countries operated in

Opex costs	Units	2011A	2012A	2013A	2014A	2015A	2016A
Gabon	$/boe	25,4	22,0	22,0	22,0	22,0	22,0
Ivory Coast, Eq Guinea, Congo (Brazzaville)	$/boe	10,0	13,0	13,0	13,0	13,0	13,0
Mauritania- variable	$/boe	35,1	55,0	41,3	20,6	20,6	20,6
South Asia	$/boe	3,3	4,0	4,0	4,0	4,0	4,0
Uganda (Tanzania)- variable	$/boe	10,4	11,0	12,0	12,0	12,0	12,0
Ghana- variable	$/boe	6,6	10,0	10,0	10,0	10,0	10,0
Namibia- variable	$/boe	10,0	10,0	10,0	10,0	10,0	10,0
UK SNS - variable	$/boe	19,4	21,0	21,0	21,0	21,0	21,0
The Netherlands	$/boe	17,1	22,0	22,0	22,0	22,0	22,0
Sierra Leone and South America - Varable	$/boe	8,1	8,5	8,7	9,0	9,0	9,0
Suriname	$/boe	4,6	4,9	5,0	5,1	5,1	5,1
Liberia - variable	$/boe	7,0	7,3	7,6	7,6	7,6	7,6
Achieved opex cost	**$/boe**	**12,32**	**14,20**	**12,61**	**12,11**	**11,62**	**10,99**

Source: Tullow Oil

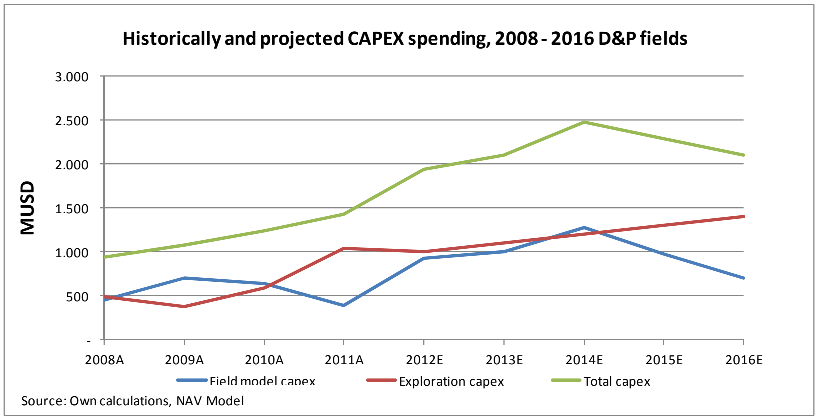
As seen in the figure, there can be large differences in opex between different countries. One reason for this is the complexity of the area of operation, from the water depth to different operational logistical challenges.

3.3.1.6 CAPEX

Capital expenditures are the investments associated with the exploration, appraisal, development and/or production part in a field. There are often several years between discovery and production, and large amounts are used to plan and develop the fields before production can start, which indicates a high capital demand.

As previously explained, Tullow operates a self funding E&P model, where “safe” assets like the UK fields fund riskier assets like the African frontier countries. Tullow has during the last decade grown from a small local player to a large international player. With a portfolio of over 100 fields, many within the exploration phase, the capex must be prioritized to the fields with the highest shareholder return. The last two years a high share of the total capex has been allocated to Ghana due to the Jubilee prospects, and this will continue during the next years in the development of the neighbouring fields and West Africa. In addition new areas in Uganda, South America and Kenya arise, which will demand further capex going forward. Tullow therefore tries to allocate the “capex pie” after expected shareholder return, to maximize the value of the company.

Figure 3.9 Historical and Projected CAPEX spending, 2008 - 2016



In 2011, 57% of capex was allocated to Ghana and Uganda, and over 83% to Africa in general. Tullow estimates a total capex of $1.990m in 2012, which is roughly divided 50-50 between development- and exploration capex. The development capex will be concentrated around Jubilee and the TEN development in Ghana and Lake Albert in Uganda. The exploration capex will mainly be focused on the remaining prospects included in the WAP. In Figure 3.9 capex tend to fall after 2014, but this is because the development projects beyond 2015 are not included in the numbers, similarly with the South American assets.

3.3.1.6.1 **Model inputs**

Table 3.10 gives an overview over both the capex the last four years, and our estimates for the next 5 years used in the model. Total capex is the sum of development capex and exploration capex. Development capex is the estimated capex within each of the producing fields[96], and the fields that are expected to start producing within 1 – 2 years. South America, Kenya and other key areas with an expected production start between 2015 and 2017 are not included. Exploration capex is the investments in exploration and appraisal, guided by Tullow´s Fact Book. This includes costs associated with fields not included in the above described development capex, which are placed under the exploration part in the NAV model.

96 Fields included in commercial NAV

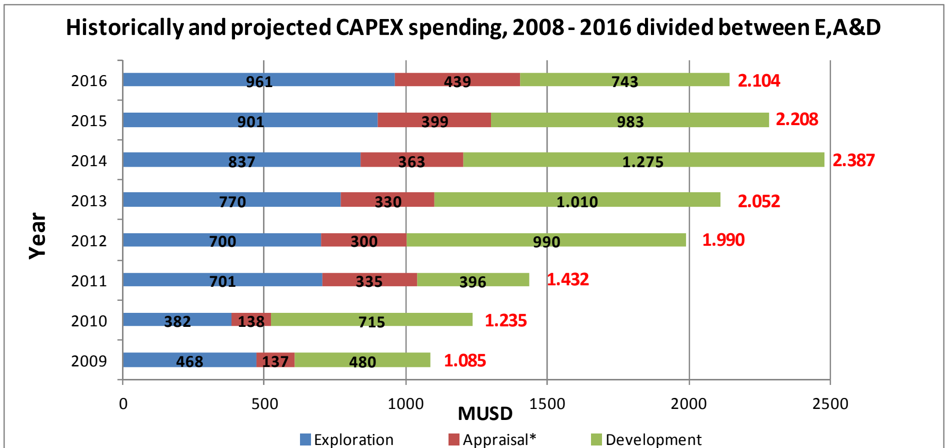
Table 3.10 CAPEX Split, development and exploration CAPEX, 2008 - 2016

Capex		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Europe	$m		(116)	(70)	(57)	(106)	(123)	(45)	(38)	(38)	(38)
Africa	$m		(241)	(421)	(483)	(559)	(818)	(965)	(1.237)	(945)	(705)
South Asia	$m		-	-	-	-	-	-	-	-	-
Development capex - existing fields	$m		(357)	(491)	(540)	(665)	(941)	(1.010)	(1.275)	(983)	(743)
Development capex (check)	$m		(357)	(491)	(546)	(711)	(933)	(1.002)	(1.275)	(983)	(705)
Development capex	$m	(177)	(456)	(707)	(637)	(396)	(933)	(1.002)	(1.275)	(983)	(705)
Exploration capex	$m	(375)	(489)	(378)	(598)	(1.036)	(1.000)	(1.100)	(1.200)	(1.300)	(1.400)
Total capex	$m	(552)	(946)	(1.085)	(1.235)	(1.432)	(1.933)	(2.102)	(2.475)	(2.283)	(2.105)
% change		66%	71%	15%	14%	16%	35%	9%	18%	-8%	-8%

Source: Own calculations, NAV model, Company Data

It is assumed that the exploration capex will increase with $100m from 2013. As clearly stated above, the African assets consist of the largest share of Tullow's capital budget, both within the development capex and the exploration capex. Figure 3.10 gives an overview of the split between exploration, appraisal and development capex.

Figure 3.10 Historically and Projected CAPEX Spending, 2008 - 2016 between E, A & D



Source: Own calculations, NAV Model *Appraisal levels increase with 10% p.a. from 2012 for illustration purpose

3.3.2 Production Forecast

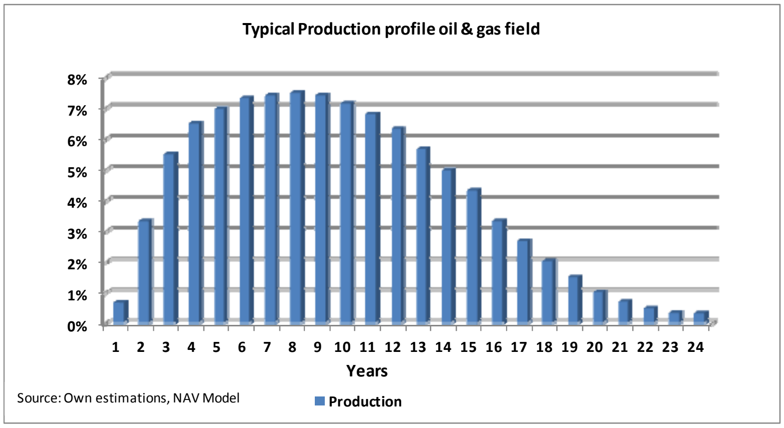
3.3.2.1 Typical production profile

There are several different factors that affect the overall production of an oilfield. The first well drilled will give a certain flow of oil per day, and additional producing- and infill wells will then be drilled on strategic places to finally reach a total "maximum" extraction rate for the field. This means that depending on the reservoir, the flow will most likely increase during the first years because of more wells drilled, until it reaches its plateau production. Through further water and/or gas injection and adjustment of the flow, the company will reach the well's ideal production profile. The water and gas injection is used to create pressure in the basin, and ultimately push the oil up from the reservoir.

A factor that might limit the production flow is the capacity of the production vessel. An example is in the Jubilee field, where the capacity for the FPSO unit is 120 kbopd. Today the production averages between 70 – 90 kbopd, but during the development time further wells will be drilled and tied back, which can result in a production close to or limited by the FPSO capacity[97].

In the NAV model, the following production profile is used as a standardized profile, except from certain key producing assets that have been calculated more carefully.

Figure 3.11 Typical Production Profile for Oil and Gas



3.3.2.2 Jubilee phase 1a

To illustrate how the different spreadsheets are built in terms of production profile, the profile for Jubilee in Ghana can be used.

Table 3.11 Jubilee Production Profile 2010 – 2029

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Field production profile	470	95%		0,0%	0,1%	5,1%	6,2%	8,5%	8,5%	8,5%	8,5%	7,5%	7,5%	5,5%	4,8%	4,0%	3,5%	3,0%	2,8%	2,5%	2,4%	2,3%	2,2%	2,0%	0,0%
Field production		kboe/d	0	0	1,3	66,2	80	109	109	109	109	97	97	71	62	52	45	39	36	32	31	30	28	26	0
Production grow th						5044%	21%	37%	0%	0%	0%	-12%	0%	-27%	-13%	-17%	-13%	-14%	-7%	-11%	-4%	-4%	-4%	-9%	-100%
Cumulative production		mboe	0	0	0	25	54	94	134	174	214	249	284	310	333	351	368	382	395	407	418	429	439	449	449

Source: Ow n calculations, NAV model

The table shows how the production profile of Jubilee is used to distribute the production over the reservoirs estimated life. This profile is based on Tullow´s guidance, and not by the standardized production profile. The amount of 470 mmboe is out of 700 mmboe in total P50 gross reserves in the Jubilee field. The field production is measured in thousand barrels per day, or kboed. To find the daily equivalent, 470 is multiplied with the percentage and divided by 0,365 when the profile is per year. The cumulative production is in mmboe and it is estimated that Tullow is able to extract 95% of the measured reservoirs.

97 Tullow: Major projects, Jubilee field

For the producing areas actual and estimated numbers for previous and present year are given, and is used in the overall production calculation.

3.3.2.3 Relationship between reservoir and daily production

It can be difficult to understand the relationship between reservoir levels and the daily production. Table 3.12 below shows a producing field´s projected lifetime in years as a function of the P50 reservoir amount and the daily production.

Table 3.12 Reservoir lifetime in years as a function of daily production and reserves

	Production per day (kboepd)				
Reservoir Base P50 mmboe	10000	50000	75000	100000	125000
25	7	1	1	1	1
50	14	3	2	1	1
75	21	4	3	2	2
100	27	5	4	3	2
200	55	**11**	7	5	4
400	110	22	15	11	9
600	164	33	22	16	13

Source: Own calculations

To calculate the equivalent yearly production if Tullow produces 50 kboed, the equation below can be used.

$$Total\ production\ in\ one\ year = 50\ \times 0{,}365 = 18{,}25\ mmboe$$

To find the projected lifetime of the prospect, the total reserves are divided with the total yearly production[98]. The equation below finds the projected lifetime if the reservoir amounts to 200 mmboe.

$$Projected\ lifetime\ of\ prospect = 200\ \div 18{,}25\ \approx 11\ years$$

Therefore, with a production of 50.000 barrels of equivalents per day, the yearly production will be approximately 18,25 million boe. A prospect with reservoir levels of 200 million boe can therefore produce oil over 11 years with 50.000 boe in daily production. In basic revenues this accounts for $5m per day, with an oil price of $100/bbl.

3.3.2.4 Modelled production per day

Tullow has production in eight countries today, not accounting for the assets in Pakistan and Bangladesh that are in the process of being sold. During the last years Tullow has increased their daily production, especially due to the development of Jubilee, and further expansion is planned in the years to come.

98 This is conditioned that extraction rate is 100% and that production per day is constant

The upcoming years will be very important for Tullow in their process of developing new fields like Jubilee. Jubilee was their first large project as an operator, but in the upcoming years new areas like Uganda, South America and Kenya are in line to be developed by the company. The next two – three years are therefore critical for Tullow, as they have to show the market their ability to further develop and operate their asset base in a reasonable way. Their daily production is, after the models estimates, supposed to increase over 130% during the next 5 years, which will require well-planned operations from Tullow´s side. Table 3.13 lists the projected WI production per day after producing countries. The table does not include Asian assets after 2011.

Table 3.13 Daily WI Production split 2007 - 2022

Daily WI Production split between producing countries from 2007A - 2022E

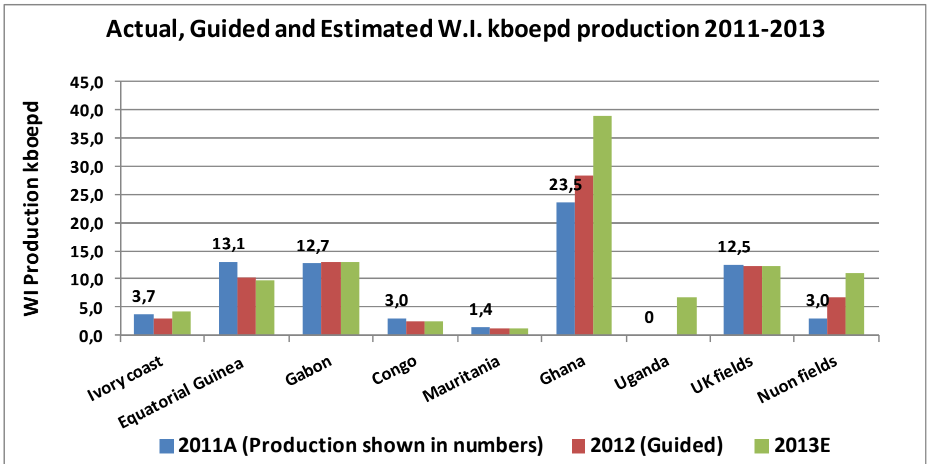
Daily WI production	Oil/gas	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Field		kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d	kb/d
Ivory coast		6,3	6,1	5,0	3,9	3,7	3,0	4,3	4,6	4,4	4,2	4,0	3,9	2,7	1,9	1,3	0,9
Equatorial Guinea		10,5	11,1	11,3	16,0	13,1	10,3	9,8	9,0	7,9	7,0	5,9	5,0	4,1	3,1	2,4	1,8
Gabon		14,7	12,9	11,9	13,0	12,7	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	9,1	6,4	4,5
Congo		1,6	2,6	3,1	3,3	3,0	2,4	2,4	2,4	2,4	2,4	2,4	2,4	2,4	2,4	2,4	2,4
Mauritania		2,8	2,2	2,1	1,5	1,4	1,3	1,3	1,3	4,3	13,1	17,6	17,8	20,0	17,8	14,8	11,8
Ghana		0,0	0,0	0,0	0,5	23,5	28,4	38,8	38,8	77,3	117,0	112,4	112,4	101,1	85,1	65,8	54,0
Uganda		0,0	0,0	0,0	0,0	0,0	0,0	6,7	33,3	55,0	65,0	70,0	73,4	74,2	75,0	74,2	71,7
Africa		**35,9**	**35,0**	**33,4**	**38,2**	**57,4**	**58,4**	**76,3**	**102,4**	**164,3**	**221,7**	**225,4**	**227,9**	**217,5**	**194,3**	**167,3**	**147,1**
UK fields	gas	23,9	20,2	14,5	13,2	12,5	12,2	12,2	12,2	12,2	12,2	12,2	12,2	1,7	1,0	0,0	0,0
Nuon fields	gas	0,0	0,0	0,0	0,0	3,0	6,8	11,1	13,3	11,1	10,4	6,7	3,3	1,5	1,5	1,5	1,5
Europe		**23,9**	**20,2**	**14,5**	**13,2**	**15,5**	**19,0**	**23,3**	**25,5**	**23,3**	**22,6**	**18,9**	**15,5**	**3,1**	**2,5**	**1,5**	**1,5**
WI production		**67,5**	**65,2**	**58,3**	**57,9**	**78,1**	**77,4**	**99,6**	**127,9**	**187,6**	**244,3**	**244,2**	**243,4**	**220,6**	**196,8**	**168,7**	**148,6**
Oil production		35,6	34,4	32,9	37,9	56,9	58,2	75,6	101,7	163,7	221,4	225,2	227,8	217,5	194,3	167,3	147,1
Gas production		31,9	30,8	25,4	20,0	21,2	19,2	24,0	26,2	23,8	22,9	19,0	15,6	3,1	2,5	1,5	1,5
% oil production		53%	53%	56%	65%	73%	75%	76%	80%	87%	91%	92%	94%	99%	99%	99%	99%
% gas production		47%	47%	44%	35%	27%	25%	24%	20%	13%	9%	8%	6%	1%	1%	1%	1%

Source: Ow n calculations, NAV model

The actual numbers from 2011 and estimated numbers for 2012 are guided by Tullow[99]. By disposing their assets in Asia, Tullow will focus its activities on the areas where they claim to have a strategic advantage. Figure 3.12 gives an overview of actual production in 2011, guided production in 2012 and estimated production for 2013.

99 Tullow: Fact Book 2011

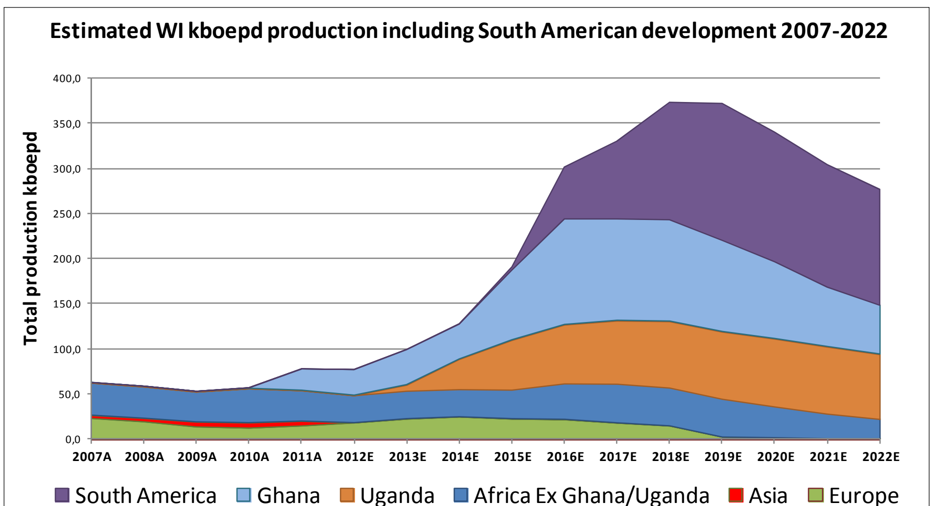
Figure 3.12 Actual, Guided and Estimated WI production 2011 - 2013



Source: Own calculations, NAV Model, Tullow Oil

To illustrate their process in becoming a large international player, their historical production per day can be graphically illustrated. Figure 3.13 states their growth historically and their projected high growth the next 10 years.

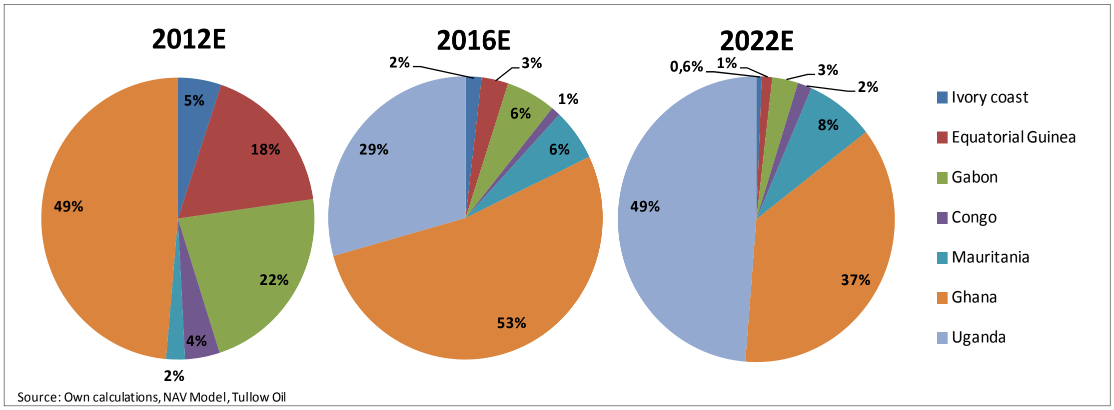
Figure 3.13 Estimated WI production including South America, 2007 - 2022



Source: Own calculations, NAV Model

In Africa, Tullow is gradually shifting its asset base from having several smaller producing assets to fewer but larger assets. Figure 3.14 clearly shows that Ghana is the largest contributor to Tullow´s WI production today, and that Uganda will be important in the years to come. The recent exploration success in Kenya also indicates that this will become an important asset as well, but it is on a too early stage to be included.

Figure 3.14 Estimated African WI Production distribution 2012-2016-2022



It can be discussed to what extent Tullow becomes too dependent on single assets, but in the figure above neither South America nor Kenya are included. In addition, Tullow has several unexplored licenses, which might become important for the company the next 2-5 years.

3.3.3 WACC

When discounting the computed cash flows, the Weighted Average Cost of Capital is used. The equation contains the cost of each capital component multiplied by its proportional weight relative to enterprise value.

$$WACC = r_e * \frac{E}{EV} + r_d * (1 - T_C) * \frac{D}{EV}$$

This section estimates the different factors included in the formula, before Tullow's WACC is calculated in the end.

Cost of equity $r_d = 10{,}1\%$

Tullow's cost of equity, is determined using the Capital Asset Pricing Model (CAPM). The CAPM states that the expected return on an asset equals the risk-free rate plus a risk premium, for bearing the excess risk.

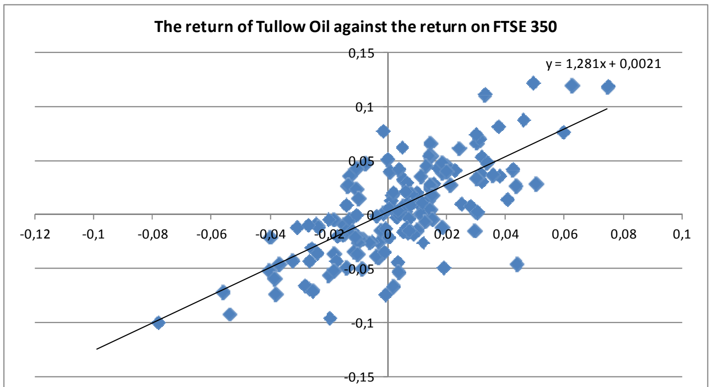
$$CAPM = E(r_e) = r_f + \beta * \left[E(r_m) - r_f\right]$$

The argumentation behind each of the CAPM components will be explained below.

Beta $\beta = 1{,}28$

The Beta has been calculated using the return on Tullow's shares against the return on the FTSE 350 the last three years. Both weekly and daily stock prices were used to make sure the result was not biased too much. Both these calculations provided a beta of 1.28. The relationship is illustrated in the figure below.

Figure 3.15 The return of Tullow Oil against the return on FTSE 350



Source: Own work based on: Bloomberg

<u>*Risk-free rate*</u> r_f = *1,95%*

The CAPM assumed that the risk-free asset has a beta of 0, thus a zero covariance between the return on the market and the asset. The risk-free rate is determined by looking at the rate of return on government securities with approximately the same maturity as our time horizon. The majority of Tullow's capital, investments, revenue and costs are noted in USD, hence we consider the 10-year US Treasury bonds. The interest rate on the 10-year US Treasury bond was 1,95% the 30th of April 2012, and this rate is used as the risk-free rate.

<u>*Market risk premium*</u> *MRP = 6,5%*

The market risk premium (MRP) is defined as the difference between the expected return on the market portfolio and the risk-free rate. We determine the expected market premium by examining both historical values and current market expectations.

The historical premiums on the American market have varied significantly between 1928 and 2010. Throughout this period the arithmetic average of the market risk premium of the S&P 500 against the T-Bills averaged 5,79% [100]. Many studies have found evidence to conclude that historical levels of the equity risk premium are not a good proxy for future estimations of its value, and that it should be lower than historically observed[101]. However,

100 Aswath Damodaran: Annual returns on Stock – T-Bills: 1928 – 2011

101 Timothy P. Lavelle: The Equity Premium Puzzle: A model for its behaviour

the market premium on the American market today implied by the renowned Stern Professor Aswath Damodaran is 6,04% which suggests otherwise[102].

Another way of estimating the market premium is to look at what risk premium is required by various players on the financial market. A survey conducted in 2011 investigates the market risk premium used by analysts, professors and companies in 56 countries around the world. The survey indicates that the average MRP required in United Kingdom is 5,3% with a standard deviation of 1,6, while the average MRP required by analysts and companies in the African countries included in the analysis is 6,7% with a standard deviation of 2,0.

As most of the company's reserves and operations are situated in Africa, it makes sense to choose a MRP closer to the 6,7% in Africa than to the 5,3% in UK where Tullow is listed. However, surveys based on expectations tend to be optimistic and often "*tell us more about hoped-for-returns than about required returns*"[103], and 6,7% may therefore be a somewhat high estimate. Considering this, as well as Damodaran's implied market premium of 6,04%, we set the market return to be 6,4% in the future.

The CAPM can now be derived based on the above analysis.

$$r_e = 1{,}95\% + 1{,}28 * 6{,}4\% = 10{,}142\%$$

An alternative could be to conduct separate return on equity for the "risky assets" (frontier markets) and the "safe assets" (developed countries). However, based on discussions with Tullow analysts, the additional risk imposed by operating in frontier markets is rather accounted for in the risk weighting in the NAV model. The return on equity of 10,14% is thus used for the company as a whole.

<u>*Cost of debt*</u> $r_d = 4{,}3\%$

A company's cost of debt is defined as the required rate of return on external capital. Tullow has divided their debt into 5 different maturities: less than 1 month, 1-3 months, 3 months to 1 year, 1-5 years and 5+ years, with approximately 90% of their interest bearing debt in the 1-5 years category. The weighted average effective interest rate for all maturities was 4,3% in 2011[104].

102 Aswath Damodaran: Implied Premiums on the US market

103 Illmanen (2003): Expected returns on stock and bonds

104 Tullow: Annual Report 2011 – Note 19, Financial Liabilities (Page 142)

Capital structure *Equity = 83%, Debt = 17%*

Net debt is calculated as gross debt, shown in the balance sheet, less cash and cash equivalents. As of Dec 31st 2011, the company had net debt of $2.854m, and equity of $4.766m, which gives a net debt ratio of 60%[105]. Tullow has significantly reduced its net debt following the completion of the $2,9bn farm-down with Total and CNOOC, resulting in net cash of $164m at the cut-off date. Total lending facilities amount to $4,15bn consisting of $3,5bn in reserved based lending facilities to be used for capital investments, and $0,65bn in additional corporate facility for liquidity control. The average debt ratio based on estimations the next five years is 17%, and this is the debt ratio assumed when conducting the WACC.

Corporate tax rate $T_c = 40\%$

Tullow estimates that the weighted average tax rate will lie within 37% - 42% in 2012. A tax rate of 40% is utilized in the NAV model based on this estimation. This is a higher than in 2011 (32%) due to expected increase in profit before tax, especially from the Ghanaian assets.

Conclusion WACC *WACC = 8,85%*

Finally the equation below illustrates the calculation of WACC using the formula displayed above.

$$WACC = 10{,}142\% * 0{,}83 + (1 - 0{,}40) * 4{,}3\% * 0{,}17 = 8{,}8564\%$$

A WACC of 8,8564% may seem low considering their operations in Africa, but this is mainly due to the exceptionally low interest rates seen today. It is in our opinion that all of the inputs are well argued for and that they are the best estimates as of today.

Similarly, the analysts covering Tullow all use a WACC between 9 – 10%.

105 Tullow: Annual report 2011 – Note 19, Page 140

3.3.4 Modelling Essential Fields

In modelling the different fields, two methods have been used as explained in the NAV introduction. The first and main method is where the main fields have been estimated in terms of all the input factors, mainly guided by Tullow. The different taxation regimes and PSC´s are found in the specific contracts between the respective country and the original contractors for each individual field[106]. The second method is where the un-risked value for a respective field is found using the EV/BBL for a similar field within the same area. The methods used for the specific countries will be explained in the next part, where all amounts are gross values.

In part 2.2 - Asset base, the reservoir levels and potential prospects were presented, to give an overview of Tullow`s assets. In this part the input assumptions used in the model will be explained. Tullow guides their 12 month exploration and appraisal programme in their Fact Book and this is the fundament for the exploration NAV. It is important to notice that it is the P50 values that are used in the model, and not the potential upside levels, or P10.

Table 3.14 Modelling Essential Fields, Overview

Modeling essential fields						Projected Development CAPEX			Risk Weighting	
Country	Net P50 Core*	Net P50 Exploration	Weightet WI	2011A KBOED Production	2012E KBOED Production	Net 2012	Net 2013	Net 2014	Contingent	Exploration
Ivory Coast	13	152	31%	3,7	3,0	-43	-21	-19	41%	30%
Equatorial Guinea	26	-	14%	13,1	10,3	-50	-48	-41	-	-
Gabon	38	21	83%	12,7	13,0	-200	-100	-50	-	50%
Congo	88	-	11%	3,0	2,4	-3,3	-1	-0,55	-	-
Mauritania	407	46	22%	1,4	1,3	-97	-170	-170	-	20%
UK	44	-	100%	12,5	12,2	-70	-	-	62%	-
Netherlands	42	11	18%	3,0	6,8	-52,5	-45	-37,5	50%	50%
Ghana	512	354	43%	23,5	28,4	-412	-428	-576	70%	72%
Uganda	367	185	33%	-	-	-110	-367	-550	-	40%
Namibia	155	-	31%	-	-	-	-116	-232,5	60%	-
French Guiana	48	184	28%	-	-	-	-	-	80%	30%
Guyana	-	129	30%	-	-	-	-	-315	-	20%
Suriname	-	40	40%	-	-	-	-	-375	-	30%
Kenya	18	404	31%	-	-	N/A	N/A	N/A	50%	37%
SUM	1757	1524		72,9	77,4	-1038	-1296	-2367		

* Core values are the commercial and contingent values combined

Source: Own Calculations, NAV Model and Company data

106 These contracts are too large in size, to be included in the thesis, but specification to download them lies in the source of reference under: Tullow: Petroleum Agreements

3.3.4.1 West & North Africa

3.3.4.1.1 Ghana

Table 3.15 Prospect Overview Ghana

Ghana	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	Jubilee Phase 1&1a	35,5%	167			
Ghana UNIT	Jubilee P50 remainder - Phase 1b	38,2%	78			
Ghana DWT	TEN	49,95%	140			
Contingent*	Mahogany East Area	26,4%	21	120	32	80%
Ghana WC3	Teak P50	26,4%	32	180	48	80%
Ghana WC3	Akasa-1	26,4%	8	48	13	80%
Ghana UNIT	Jubilee- Associated gas + TEN	38,2%	66	260	99	50%
Exploration	Ntomme, Owo, Enyenra appraisal	49,95%	200	550	275	80%
Ghana DWT	Tweneboa Deep	49,95%	60	300	150	60%
Ghana DWT	Sapele-1	49,95%	37	160	80	60%
Ghana DWT	Wawa 1	49,95%	30	150	75	60%
Ghana WC3	Teak-4	26,4%	26	200	53	50%
		Sum:	*866*	*1968*	*823*	

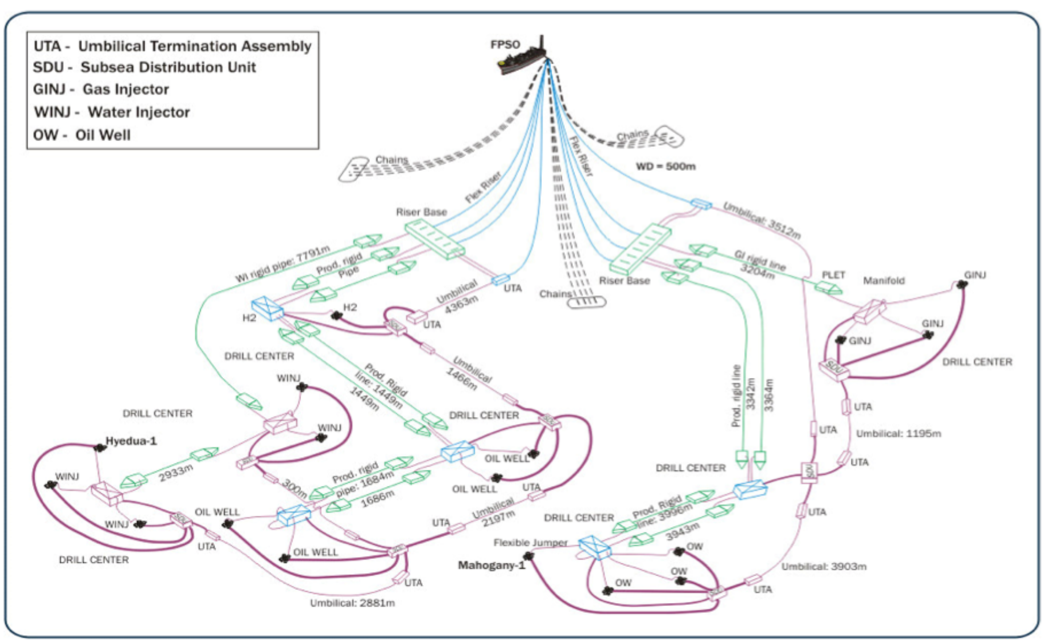
Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

The Ghanaian assets are Tullow's most important assets in terms of production, growth and value. The transformation to becoming a large international E&P player and acknowledged offshore operator came along with the development of the Jubilee field in Ghana. In addition, the continuous exploration has revealed new prospects similar to Jubilee, and these have been the basis for the overall WAP.

The development of Jubilee and the adjacent prospects are divided into different phases, seen in part 2.2 - Asset base. Phase 1 finished October 2011 with completion of 17 wells. Figure 3.16 illustrates the complexness of the project and the subsea production park.

Figure 3.16 Overview of Phase 1 development in Jubilee, Ghana



Source: Tullow Oil, Project Information Posters, Slide 5

Working Interest (WI): In calculating the estimated value of the assets in Ghana, different WIs apply. The reason for this is that the prospect lies both in West Cape Three Point (WC3) and Deep Water Tano (DWT), and the WI for Jubilee is therefore a combination of the two fields, which is called Jubilee/Ghana UNIT (UNIT). The ownership of Jubilee is split 50 – 50 between WC3 and DWT, but in October the UNIT partnership completed their first equity redetermination, which basically is a renegotiation of the equity split of the ownership. Tullow´s share was reduced to 35,48% for Phase 1 and 1a despite of their acquisition of E.O. Group´s share in WC3. The acquisition increased their share in the WC3 with 3,5%. Table 3.16 shows the different licences and prospect in Ghana.

Table 3.16 Tullow Oil Working Interests in Ghana

Partner	Deep Tano	WC3	Phase 1&1a	Phase 1b
Tullow Oil	49,95%	26,4%	35,5%	38,2%

Source: Tullow Oil, Group Licence Interests

As seen in the figure, a WI of 35,5% is used for Phase 1 and 1a. For Phase 1b, a WI of 38,2% is used, which is a unitization between the fields conducted and guided by Tullow. For the prospects associated solely to DWT and WC3 their respective WI is used.

In addition to the oil found in Jubilee and TEN, gas reservoirs are also present. The total amount of P50 levels are set to approximately 800 bcf (144 mmboe) in Jubilee and 400 bcf (72 mmboe) in TEN. Of the Jubilee gas, 20% will be used as fuel, 40% will be exported to Ghana with a significant discount, and the remaining 40% will be re-injected to maintain the pressure. Of the 2400 bcf (432 mmboe) estimated in the TEN area, only 30% is expected to be exported, which gives a total gross amount of 173 mmboe. Regarding the NAV model, the EV/BBL from Jubilee phase 1 & 1a is first discounted back 3 periods to account for production start in 2015 before multiplied with 35% to account for the price discount[107].

Taxation: Taxation in Ghana is based on income tax and royalty. First, 5% is subtracted from gross revenue in royalties, than 35% is subtracted from the taxable base. Finally an Additional Profit Tax (APT) of approximately 25% is applied.

CAPEX: The prospects in Ghana cover the whole E&P value chain, which demand investments continuously as the project progresses. Tullow's guided capex of $9/bbl in the development of Jubilee phase 1 & 1a, indicates a total gross capex of $4,4bn allocated from

107 Tullow indicated export pricing of $5 – 6/mmscf. 35% of $100/bbl indicates this price. (100*0,35/6 = 5,8/mmscf).

2008 until 2012. In addition, $400m is added in 2011 and 2012 in recompletions[108] of the existing wells.

Capex for Phase 1b is guided to be $10/bbl, which indicates a total gross capex of $2,05bn, allocated over five years starting in 2013. Similar costs are associated with the TEN development, resulting in a six year split of gross $2,8bn starting in 2012. See appendix 36 for further details.

In the DCF calculation of "Ghana from 2015" which applies for Mahogany, Teak and Akasa, $11/bbl is guided as capex, if Tullow and its partners decide to develop a standalone project including purchase of a FPSO. If the prospect is tied back to the Jubilee development, capex will decrease to $10/bbl. In the model though, $11/bbl is assumed which indicates a total capex of $11bn divided between Tullow and its partners from 2013 – 2017[109].

It is important to notice that only capex from Phase 1 & 1a, Phase 1b and TEN calculations are included in the developing capex linking to the cash flow statement and balance sheet. This is due to the uncertainties surrounding the final decision in terms of the "Ghana from 2015" included fields.

<u>*OPEX*</u>***:*** Tullow guides opex to be $10/bbl for 2012 and going forward.

<u>*Risk weighting*</u>***:*** The three prospects in the contingent part, Mahogany, Teak and Akasa, and they are all given a risk weighting of 80%. These fields will be developed, but when and how is still not determined, and a conservative view is therefore applied. The final amount of gas and the price to which it will be exported to Ghana is still uncertain, and it is therefore risk adjusted by 50%.

The first three prospects Ntomme, Owo and Enyenra are all given a risk adjustment of 80%. The prospects are in the appraisal phase, and will provide further information for Tullow to determine future development. The rest of the prospects are given a risk weighting of 60%, except the Teak exploration at 50%, due to their somewhat earlier position in the exploration process.

Because of Tullow´s close relationship with the Ghanaian government and Ghana´s TI ranking of 69 (CPI score: 3.9), second best among the African countries, political risk given less weight in the risk weighting.

108 Recompletion involves re-entering previous wells to repair and enhance their productivity.

109 In the calculation of "Ghana from 2015" an initial reserve base of 1000 mmboe is assumed to find the EV/BBL. Therefore the capex will reflect the assumed reserves providing a total of $11bn in capex. **See** appendix 37.

3.3.4.1.2 Ivory Coast

Table 3.17 Prospect overview Ivory Coast

Ivory Coast	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	Espoir	21%	13			
Exploration	Paon	45%	92	500	225	30%
	Kosrou	22%	59	650	145	30%
		Sum:	*165*	*1150*	*370*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: The taxation system in Ivory Coast is based on PSC´s with the government and is shown below. This is the contract for the existing production in the Espoir field, where both gas and oil are produced. The PSCs for the two exploration fields are somewhat different and can be seen in appendix 24 and 25.

Table 3.18 PSC Ivory Coast

PSC - Gas production				
Production		mcf	Kboe/d	Contractor Share
kboe/d	<	68	11	49%
kboe/d	<	135	23	47%
kboe/d	<	338	56	42%
kboe/d	<	675	113	37%
kboe/d	>	675	113	32%

PSC - Oil Production			
		Production	Contractor Share
kboe/d	<	10	49%
kboe/d	<	20	47%
kboe/d	<	30	42%
kboe/d	>	> 30	37%

Source: Company Data Ivory Coast, NAV Model

CAPEX: To maintain the operation in and around the Espoir field, an eight well infill campaign will commence during 3Q 2012. The costs are estimated to be around $300m divided between 2012 and 2013, where Tullow has a WI of 21%. Due to this tieback campaign, the production per day is assumed to increase until 2016 when it will start declining again.

In addition to the producing field, further explorations are planned for the Paon and Kosruo fields during 2012. The Kosruo well is already in progress, and the Paon well is expected to start drilling in Q3 2012. The exploration capex in this process is included in the unspecified “Exploration Capex” in the forecast, and not the development capex. To calculate the expected value of these fields a DCF model is made, where the development capex is estimated to be $10/bbl in the reservoir, which is the same as for similar prospects.

OPEX: The operating costs are guided to be $13/bbl in 2012, and this is the cost assumed going forward.

Risk weighting: The risk weighting is based on the political risk in the country in addition to the risk factor assigned to adjust the value based on P50 for technical uncertainties within the field. Transparency International's (TI) ranking of Ivory Coast is 154 with a CPI score of 2,2, implying that the country is highly corrupt. The country also scores as low as 9% on the "Rule of Law" meaning that only 9% of the agents operating in the country have confidence in the legal system and the enforcement of this. Based on this, both fields that are included in exploration NAV are given a risk weighting of 30%.

3.3.4.1.3 Mauritania

Table 3.19 Prospect overview Mauritania

Mauritania	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	Cinguetti	22%	3			
Contingent*	Tiof	22%	54	375	81	50%
	All other fields	50%	350	1050	525	40%
Exploration	Sidewinder	22%	46	430	96	20%
		Sum:	*453*	*1855*	*702*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

Taxation: The taxation regime in Mauritania is based on PSC and income tax, and there is no royalty rate payable. The contractor´s share is based on the production per day, and this will not affect the model until 2015 when Tiof is expected to commence production. The income taxation rate is 25%.

Table 3.20 PSC Mauritania

PSC - Oil Production		
	Production	**Contractor Share**
kboe/d	25	65%
kboe/d	75	60%
kboe/d	100	55%
kboe/d	>100	50%

Source: Company Data Mauritania, NAV Model

CAPEX: There is no further expected capex planned for the Cinguetti field, but the development of Tiof will demand contribution from Tullow going forward. Tullow has guided a capex/bbl of 9, which will result in a total net development capex of $500m divided over 4 years with 55% placed in the next three years. In addition to this, the exploration capex from Sidewinder in 2012 is included in the overall unspecified exploration capex. The development capex is expected to increase for the area in the years to come due to development of new prospects.

OPEX: Opex for Mauritania was in 2011 $35/bbl and expected to be $55/bbl in 2012 due to lower production, and hereby lower denominator. In 2013 it is estimated to decrease to ~$41/bbl and ~$20,6/bbl in 2014 following an increased production and stay on this level in the subsequent years. The opex for Tiof and other future development fields is expected to be approximately $15/bbl.

Risk weighting: Tiof and the rest of the fields located in the contingent NAV, are risk adjusted with accordingly 50% and 40%. Regarding Tiof, development is expected to commence within short time, but due to their low CPI score of 2,4 (ranked #143), a lower historical success rate and some other uncertainties concerning approval of development plans, it is given a risk weighting of 50%. For all the other fields in the contingent NAV, a lot of them are highly uncertain, ranging from 30% – 60%, and a conservative risk weighting of 40% is used.

In terms of Sidewinder it is to be explored in 2012, and the same arguments as above are used, therefore a conservative risk weighting of 20% is used due to its early exploration stage.

3.3.4.1.4 Equatorial Guinea

Table 3.21 Prospect overview Equatorial Guinea

Equatorial Guinea	Field	WI	P50 Net
Producing	Ceiba	14%	9
	Okume complex	14%	17
		Sum:	*26*

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: Equatorial Guinea has several taxation regimes, with PSC, income tax and royalty. Both the PSC and the royalty rate are a function of production. The PSC is based on the cumulative production and the royalty rate is based on the daily production.

Table 3.22 PSC Equatorial Guinea

PSC - Cumulative Oil Production		
Cumulative Production		**Contractor Share**
mboe	200	85%
mboe	350	70%
mboe	450	60%
mboe	550	50%
mboe	> 550	40%

PSC - Royalty rate dependent on daily production		
	Production	**Contractor Share**
kboe/d	30	11%
kboe/d	60	12%
kboe/d	80	14%
kboe/d	100	15%
kboe/d		16%

Source: Company Data Equatorial Guinea, NAV Model

The contractor share is largest in the beginning of the production life cycle, providing liquidity to the contractors in the start-up phase, before getting smaller during the prospect`s cycle. In addition, the P50 initial values lay around 200 mmboe for both fields, which means that the contractor share only declines if it is found more oil in the connected wells. The contractor share for both producing fields is 85% today. In terms of the royalty for Ceiba and the Okume complex, the royalty rate is accordingly 11% and 14%, where Ceiba is estimated to be stable and Okume to decrease over the next years. In addition to the PSC and the royalty rate, an income tax of 20% is added to the government share for both prospects.

CAPEX: Over the next three years, estimated capex for the Ceiba and the Okume prospect are respectively \$300m and \$500m. The estimation includes maintenance and development capex for both of the prospects, where infill drilling will be done to maintain the production plateau.

OPEX: The opex in Equatorial Guinea is guided by Tullow to be the same as in Ivory Coast and Congo, at \$ 13/bbl from 2012 and forward.

Due to the fact that Equatorial Guinea is only represented with producing assets in the NAV model, no risk weighing is applied.

3.3.4.1.5 Gabon

Table 3.23 Prospect overview Gabon

Gabon	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	All fields	100%	52			
Exploration	Gnondo	53%	21	90	48	50%
		Sum:	*73*	*90*	*48*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: There are various taxation regimes in Gabon depending on on/offshore fields, depth and complications in the production. The taxation regime also depends on when the respective license was awarded from the government. The overall royalty rate is set to 10%, and the specifications of the PSC are shown below.

Table 3.24 PSC Gabon

PSC - Oil Production		
	Production	Contractor Share
kboe/d	10	50%
kboe/d	20	45%
kboe/d	30	40%
kboe/d	40	35%
kboe/d	>40	30%

Source: Company Data Gabon, NAV Model

The PSC contract is somewhat more aggressive than previously shown, but the country has no direct income tax. In 2011, production in the PSC fields was 13 kboed, and is expected to stay at this level in the coming years enabling a contract share of the profit of 45%.

CAPEX: Other contractors control the development capex obliged by Tullow, and Tullow does not operate any of these fields. Therefore, the model accounts for net values for all variables. It is assumed that Tullow must contribute with about $ 350m over the next three years to complete the infill drilling in the various fields in the area. The exploration capex planned for the Kiarsseny license is not accounted for, as this is included in the overall unspecified exploration capex.

OPEX: The actual opex for 2011 and guided opex going forward are at $ 22/bbl.

Risk weighting: Good seismic data was gathered during 2011, the country has a mature oil production and a good ranking in terms of political risk (#100) and "Rule of Law" (36%) relative to other African countries. However, as many of the prospect are still in a early phase of development, with high uncertainties, a risk weighting of 50% is implemented in the calculation of the Gnondo prospect.

3.3.4.1.6 West African Jubilee Play

Table 3.25 Prospect overview West African Play (WAP)

West African "Jubilee" Play	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Exploration	Jubilee/Zaedyus analogues	26%	1459			20%
		Sum:	*1459*	*0*	*0*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Certain calculations and estimations have to be done to calculate an approximate value for the future development of the WAP, to include it in the valuation. It is included due to its active part of Tullow´s strategy, and it is in many ways the fundament of large parts of their African operations. Table 3.26 shows how the prerequisites for equity interest and EV/BBL are calculated for the WAP.

Table 3.26 Prerequisites for West African Play (WAP)

West African Play - license equity - average		
Country	**Block**	**Equity**
Liberia	15 - Montserrado	25%
Liberia	16	25%
Liberia	17	25%
Sierra Leone	Mercury	20%
Sierra Leone	Jupiter	20%
Ivory Coast	Paon	45%
Ivory Coast	Kosrou	22%
Ghana	WC3	26%
Ghana	DWT	50%
Simple average inclusive Ghana		29%
Simple average exclusive Ghana		26%

Source: Own calculations, NAV Model, Company data

EV/BBL West African Play - average	
Country	**$/bbl**
Liberia 2015	12,4
Sierra Leone 2015	18,6
Ivory Coast 2015	11,5
Ghana 2015	13,9
French Guiana 2015*	16,7
2015 avg	14,6
2016 avg (Future Value)	13,4
Blended EV/BBL	14,0

* 2018 values are adjusted to 2015 values

Equity interest: To calculate an estimated equity interest, a simple average of the licences in the three countries west of Ghana is calculated. Ghana is not included due to a conservative view as it would have increased the equity interest.

Valuation: In the EV/BBL calculations, respective EV/BBL is gathered from the different countries included in the WAP, where production start is estimated to 2015. For French Guiana production is assumed to commence in 2018 and this is adjusted to match the other countries with start in 2015, leading to a higher EV/BBL for the area. To calculate the final EV/BBL, the 2015 average is calculated before finding the 2016 future value as seen in Table 3.26. This is done to create a best possible unbiased estimate, before taking the average of the 2015 and 2016 which is called the "Blended EV/BBL". To account for the future value calculated, the Blended EV/BBL is discounted three periods back to 2012 levels, and the EV/BBL used in the NAV model amounts to $10,9/bbl. This is the estimate used to find the value today for the future WAP development.

Reservoir estimates: The Jubilee field has P50 values of 700 mmboe, and this is used to calculate the possible reservoirs in the remaining eight countries. Therefore a P50 value of 5,6 bnboe is included in the exploration NAV[110].

Risk weighting: Even though Tullow´s long term strategy supports the development of WAP, and several exploration results and seismic data support their theory, there are many obstacles going forward. There is political risk in several of the included countries, operational risk in terms of complicated reservoirs and, of course, the risk that their theory is

110 Jubilee analogues of 700 mmboe in P50 values, eight countries → 700 * 8 = 5.600 mmboe

mistaken. A risk weighting of 20% is therefore applied in the model, which is a weighted estimate based on the above mentioned parameters.

3.3.4.2 South & East Africa

3.3.4.2.1 Uganda

Table 3.27 Prospect Overview Uganda

Uganda	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Commercial	Ugandan Development	33,3%	367			
Exploration	Ugandan exploration - various wells	33,3%	185	1200	400	40%
		Sum:	*552*	*1200*	*400*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: Uganda uses royalty taxation based on production levels, PSC and direct income tax of 30%. The final entitlement factor is therefore lower relative to other countries in Africa. Both the contractor´s share and the royalty rates are determined by the daily total production from the area, as seen below.

Table 3.28 PSC Uganda

PSC - Oil Production		
	Production	Contractor share
kboe/d	5	55%
kboe/d	10	50%
kboe/d	20	45%
kboe/d	30	40%
kboe/d	40	35%
kboe/d	> 40	33%

PSC - Royalty rate based on daily prod.		
	Production	Royalty
kboe/d	2,5	5,0%
kboe/d	5	7,5%
kboe/d	7,5	10,0%
kboe/d	> 7,5	12,5%

Source: Company Data Uganda, NAV Model

Based on the large reservoir levels, and hereby a large daily production, the contractor share will be at its lowest of 33% and royalty rate its highest of 12,5% in most of the project´s projected lifetime. If they discover more during the next years, it is likely that a renegotiation can be done, alternatively they can obtain a larger cost recovery rate.

CAPEX: Tullow has guided a capex of $ 5/bbl, which indicates a total gross capex of $ 5,5bn. This is split between six years with the majority to be invested during the first years. The amount also includes the planned pipeline construction to the Kenyan coast.

OPEX: Opex is guided to be $12/bbl in 2012 and increase to $12,5/bbl in 2013 going forward.

Risk weighting: The commercial part of the Ugandan development is not risked, and it is assumed that all of the 1,1 bnboe will be extracted. In the case of the exploration activity, only 555 mmboe of the estimated P50 of 1,4 bnboe is accounted for, which further is risk adjusted with 40%. There are three reasons for this. The first reason is that the whole value from the present P50 values is accounted for in the commercial NAV. Secondly, the contractors need to show progress in the development and that their partnership works in terms capital prioritization and exploration success. Thirdly, Uganda´s low CPI score of 2,3 (ranked #143) combined with the government's slow and uncertain process of approving the farm down of the Lake Albert assets, argue for a more conservative risk weighting.

3.3.4.2.2 Kenya

Table 3.29 Prospect Overview Kenya

Kenya	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Contingent*	Ngamia-1 (Block 10BB)	50%	18	53	26	50%
Exploration	Mbawa (Block L8)	20%	46	610	122	30%
	Paipai (Block 10A)	50%	58	290	145	30%
	Upside potential	30%	300			40%
		Sum:	*421*	*953*	*293*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

Valuation and risk weighting: The assets in Kenya have not been modelled due to its early stage. Instead, Wood Mackenzie estimates have been used[111] which imply EV/bbl of $ 3,5 as base case and $ 6 as upside case, quite similar to the Ugandan development. The contingent part, that includes the Ngamia prospect is valued with the base case estimates, and all the exploration prospects are valued with the upside scenario.

With second last TI ranking of 154 among the African countries (CPI score: 2,2), the political situation in Kenya has to be taken into account when risk adjusting the potential values. There is a predominant probability that there will be production in Kenya, especially in the Ngamia prospect and the surrounding basins. However, due to political risk, and the early phase of the basin development, a risk weighting of 50% is used for the contingent prospect.

In terms of the two exploration prospects that are to be drilled during 2012, a risk weighting of 30% is given. The substance for this is the existing seismic data and the geological knowledge that the contractors have. In addition, the upside potential EV/BBL is used, which substantiates a conservative risk weighting. To value the future possible

111 Bernstein Research: Tullow Makes Its First Kenyan Oil Discovery

reservoir levels in the basins surrounding the findings in the Ngamia prospect, the post "Potential upside" is created. It is accounted for a conservative gross estimate of 1 bnboe, valued with the upside EV/BBL estimates, and risk weighted with 40%. Both the estimated reservoir levels and the risk weighting are subject to adjustments in Tullow´s favour, but it is too early to account for this.

3.3.4.2.3 Namibia

Table 3.30 Prospect Overview Namibia

Namibia	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
*Contingent**	Kudu	31,0%	155	600	186	60%
		Sum:	*155*	*600*	*186*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,2 due to gas reservoir and not oil. Only for illustration.

Taxation: The taxation regime in Namibia is based on corporate taxation and royalty. The royalty rate is at 12,5%, and the corporate taxation is split in two with a base rate of 35% and then an Additional Profit Tax (APT) of 30%.

CAPEX: Tullow has guided a capex of $3/bbl, which indicates a total capex of $1,5bn. 95% of this is allocated in the years 2013 – 2015.

OPEX: Opex is guided by Tullow to be $10/bbl from production start and forward.

Risk weighting: The final investment decision is not yet taken in terms of the development of the field, but is expected to be determined during 2012. Due to this uncertainty, a risk weighting of 60% is given. Political risk is incorporated in the risk weighting, but relative to many other African countries, it is given less weight because of Namibia´s TI rank of 57, which is the best of the African countries. The Kudu prospect is not yet included in the future P&L, CF statement or balance sheet.

3.3.4.3 Europe & South America

3.3.4.3.1 UK

Table 3.31 Prospect Overview UK

UK	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	CMS/TH	100%	32			
*Contingent**	K4	23%	6	38	8	50%
	Bure N	67%	1	3	2	50%
	Katy (formerly Harrison)	23%	5	30	7	80%
		Sum:	*44*	*71*	*17*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

Taxation: The taxation regime in the UK is ordinary corporate taxation of 62%, without any further royalty or PSC.

CAPEX: During the last two years, there has been some development capex to ensure continuous production levels in form of tie backs and infill drilling. In 2012 $70m is accounted for in the model, which is the tie back of the Kathy field. From 2013 no capex is projected based on Tullow´s guidance.

OPEX: Opex for 2011 was ~ $19,5/boe and Tullow´s guidance for 2012 and forward is $21/boe. That is for the gas equivalent of one oil barrel, but in the model this amount is divided with 6 to convert it into gas equivalent, $3,5/mscf.

Risk Weighting: For the three contingent prospects, K4 and Bure North are given a risk adjustment of 50%, due to the uncertainties concerning future tiebacks and quality of the reservoirs. It is also a question if it is economical to tie back the Bure N prospect. In terms of the Kathy prospect, it is given a risk weighting of 80% due to its successful sanctioning last year. None of the fields have been modelled, and is therefore calculated with the EV/BBL from a similar field, namely the producing fields from the commercial NAV. Due to the uncertainties concerning value per barrel going forward because of difficult cost control, the EV/BBL from the commercial calculation for the producing fields have been discounted 5 periods before the value calculation is done, to be somewhat conservative in a mature and declining area.

As the UK is given a high CPI value by TI, political risk is not given much weight in the risk weighting.

3.3.4.3.2 The Netherlands

Table 3.32 Prospect Overview The Netherlands

The Netherlands	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Producing	Nuon acqusit.	15%	27			
Contingent*	Nuon and Epidote	15%	15	146	22	50%
Exploration	K8, Sigma, Vincent	30%	11	60	18	50%
		Sum:	*52*	*206*	*40*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

Taxation: The Netherlands have two types of taxes that apply to Tullow. First, the Personal Property Tax (PPT) of 50% is calculated, and then the Corporate Income Tax of

25,5%. In this way the efficient tax rate will be approximately the same as in UK, about 63%.

CAPEX: There are many activities across the Dutch assets, and large unexplored areas, which give several opportunities for Tullow and their partners. During the next years a gross amount of $1,4bn is estimated in development capex in the different prospects in the area. Tullow's WI capex is approximately $200m for the respective period, where ~70% is allocated during the next three years.

OPEX: Opex in 2011 was $17/bbl, and guided to be $22/bbl going forward. This is almost the same cost structure as in UK.

Risk weighting: For the contingent part of their Dutch portfolio, a risk adjustment of 50% is given for the planned production of the two prospects in the Noun field, and the Epidote prospect. Accordingly, 50% is used for the exploration, due to the purchase of good seismic data last year which is the fundament for the three exploration prospects. The political risk is not emphasized in the risk weighting as the Netherlands is ranked 7th in the world with a CPI score of 8.9 on TI's corruption ranking.

In the same way as with the UK contingent prospects, the value of the non-modelled prospects, contingent and exploration part, is calculated with the EV/BBL from the producing Noun fields discounted back 5 periods. In this way a conservative valuation is made to account for dry wells and an unexplored area.

3.3.4.3.3 French Guiana

Table 3.33 Prospect Overview French Guiana

French Guiana	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Contingent*	Guyane Maritime- Zaedyus	27,5%	48	263	72	
Exploration	Zaedyus-2 appraisal	27,5%	47	210	58	30%
	Zaedyus exploratory appriasal	27,5%	74	630	173	30%
	Dasypus-1	27,5%	63	510	140	30%
		Sum:	*232*	*1613*	*443*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

*Contingent P10 is not published, estimation is done by multiplying gross P50 with 1,5. This does not affect valuation, only for illustration.

Taxation: Due to its connection to France, the taxation regime in French Guiana is very favourable for Tullow. The taxation is based on royalty and corporate tax, where the rates accordingly are 12,5% and 40%, which gives a high entitlement factor.

CAPEX: The development capex is guided to be $12/bbl. This is somewhat higher than normal, due to deeper water at the licence, which makes the development and production more difficult. In the model gross development capex of $2,1bn is included, but not until 2017. Exploration capex for the ongoing E&A is included in the unspecified exploration capex.

3.3.4.3.4 Suriname

Table 3.34 Prospect Overview Suriname

Suriname	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Exploration	5 well campaign - Onshore Coronie	40,0%	40	250	100	30%
		Sum:	*40*	*250*	*100*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: Due to uncertainties in terms of PSC details, a conservative contractor share of 15% is estimated, in addition to royalty and tax rate of respectively 6% and 36%. The contractor share will most likely increase if a future development plan is approved.

CAPEX: The onshore field, which is included in the model, has a guided capex of $5/bbl. It is naturally less expensive to produce onshore, and the total gross capex amounts to $1,25bn which is projected from 2014 and three years forward. The exploration activity in the offshore field is included in the unspecified capex.

OPEX: Opex is estimated to be approximately $5/bbl when production commences. Again, the lower opex is due to onshore and not offshore production.

Risk weighting: The information concerning the onshore field is not enough at this stage to know if investments will be made or not. During 2012, the results from the 5 well campaign will determine whether or not further development will be done. Therefore a risk weighting of 30% is applied as a conservative view. It is also to be said that the PSC of fixed 15% contractor share is a relatively conservative view which in the case of further success can act as a positive catalyst for Tullow. The offshore block is not included in the NAV model. The CPI score of 3 (ranked #100) is also taken into account.

3.3.4.3.5 Guyana

Table 3.35 Prospect Overview Guyana

Guyana	Field	WI	P50 Net	P10 Gross	P10 Net	Risk Weighting
Exploration	Jaguar Fan System	30,0%	129	1180	354	20%
		Sum:	*129*	*1180*	*354*	

Source: Own calculations, NAV model, Tullow Oil. All reservoir values are in mmboe

Taxation: The PSC agreement in Guyana can be seen below. It is to be said that new agreements must be expected if the fields are to be developed in the future.

Table 3.36 PSC Guyana

PSC - Oil Production		
	Production	**Contractor share %**
kboe/d	0	47,0%
kboe/d	40	50,0%

CAPEX: Capex per barrel is similar to French Guiana and Suriname at $12/bbl which indicates a total gross capex of $2,1bn, divided over three years starting in 2014. The unspecified exploration capex also includes the exploration work that is currently ongoing.

OPEX: Opex is guided to $9/bbl.

Risk weighting: The Jaguar prospect has a gross P50 of 430 mmboe. As it is in a very early stage in the E&A process it is given a conservative risk weighting of 20%, but it is therefore a clear catalyst for Tullow if they can provide positive information from the prospect, which ultimately can de-risk the WAP further. Guyana's low CPI score of 2,5 (ranked 134), does also call for a conservative risk weighting.

4 Analysis

With the inputs described for each country, in addition to the ones not presented[112], a NAV model can be developed. The NAV model gathers all the calculated EV/BBL and uses these levels to calculate the value of each individual prospect based on its P50 reservoir levels. The advantage with the NAV model is the opportunity to break down the total estimated value into each of the different areas for further analysis. In this way it can be illustrated where in the company the value lies, and their ongoing investment decisions can be analyzed. The complete NAV model can be found in appendix 15 – 45.

112 Sierra Leone, Liberia, Ethiopia are not presented as they represent only 2% of the NAV value combined

Tullow's NAV model with 100+ licences is large and complex. In the first part of the analysis, the total output with detailed specifications regarding the most important assets will be presented. In the second part, the commercial, contingent and exploration parts of the NAV model will be presented. The important assumptions will also be elaborated, parallel with illustrations showing what countries the value derives from. All values are referred to as *pence per share* (p/share or GBp/share). In Table 4.1, the NAV output can be seen.

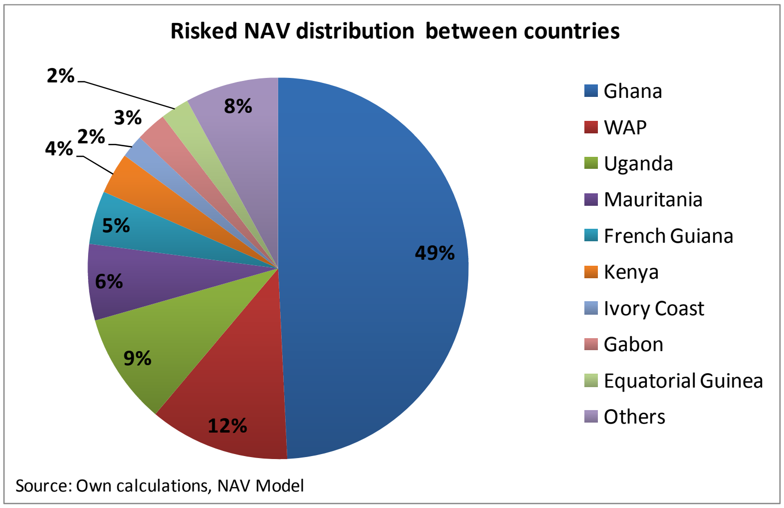
4.1 NAV Output

Table 4.1 Net Asset Value Output

Net Asset Value (NAV)		P50 gross resources	P50 working interest	EV/bbl working interest	Risk weight-ing	Unrisked EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Field WI (eq)
Country	Field	mmboe	mmboe	$/boe	%	$m	$m	p/sh	%	p/sh	p/sh	%	%
Ivory Coast		61	13	17,5	100%	229	229	16	0,9%	16			21%
Equatorial Guinea		186	26	24,5	100%	650	650	45	2,5%	45			14%
Gabon		52	52	12,1	100%	632	632	44	2,5%	44			100%
Congo		88	10	25,6	100%	247	247	17	1,0%	17			11%
Mauritania		15	3	19,6	100%	65	65	5	0,3%	5			22%
UK		32	32	9,9	100%	318	318	22	1,2%	22			100%
The Netherlands		180	27	5,5	100%	150	150	10	0,6%	10			15%
Ghana		955	385	21,3	100%	8.210	8.210	566	31,9%	566			40%
Uganda		1.100	367	5,7	100%	2.105	2.105	145	8,2%	145			33%
Commercial NAV		2.669	915	13,8	100%	12.606	12.606	869	48,9%	869			34,3%
Mauritania		950	404	9,6	41%	3.890	1.608	111	6,2%	268	157	9%	43%
Namibia		500	155	4,6	60%	709	425	29	1,7%	49	20	1%	31%
Sierra Leone		158	32	18,7	55%	590	326	22	1,3%	41	18	1%	20%
Ghana		405	127	10,6	69%	1.349	931	64	3,6%	93	29	2%	31%
Kenya		35	18	3,5	50%	61	31	2	0,1%	4	2	0%	50%
French Guiana		175	48	12,9	80%	623	499	34	1,9%	43	9	0%	28%
UK		47	11	6,5	62%	74	46	3	0,2%	5	2	0%	24%
Netherlands		97	15	3,6	50%	53	26	2	0,1%	4	2	0%	15%
Contingent NAV		2.367	810	9,1	53%	7.349	3.892	268	15,1%	506	238	13%	34%
Liberia		165	41	12	30%	515	154	11	0,6%	35	25	1%	25%
Ivory Coast		470	152	7	30%	990	297	20	1,2%	68	48	3%	32%
Ghana		755	354	16	72%	5.630	4.037	278	15,7%	388	110	6%	47%
West African "Jubilee" Play		5.600	1.459	11	20%	15.925	3.185	219	12,4%	1097	878	49%	26%
South America		1.200	353	11	26%	3.906	1.030	71	4,0%	269	198	11%	29%
Uganda		555	185	6	40%	1.062	425	29	1,6%	73	44	2%	33%
Kenya		1.345	404	6	37%	2.421	906	62	3,5%	167	104	6%	30%
Ethiopia		140	70	7	20%	455	91	6	0,4%	31	25	1%	50%
Mauritania		205	46	6	20%	292	58	4	0,2%	20	16	1%	22%
Gabon		40	21	6	50%	131	66	5	0,3%	9	5	0%	53%
Netherlands		35	11	4	50%	38	19	1	0,1%	3	1	0%	30%
Exploration NAV		10.510	3.095	10,1	33%	31.364	10.269	708	39,9%	2.162	1.454	82%	29,4%
Less exploration costs 2012						-1.000	-1.000	-69	-4%				
Net exploration NAV		10.510	3.095	9,8	31%	30.364	9.269	639	36,0%	2.162	1.454	82%	
Tariff income value	PV of future post tax CF					241	241	17	0,9%	17			
Hedging value isolated	PV of future hedging profit / loss					274	274	19	1,1%	19			
Less corporate costs	6x present value					-759	-759	-52	-3,0%	-52			
(Net debt) / net cash	Adjusted 31 December 2011					164	164	11	1%	11			
Estimated net sales revenue Asian Assets						80	80	6	0,3%	6			
Net financial items						-0,4	-0,4	-0,1	0%	-0,1			
Core NAV						12.606	12.606	869	49%	869	-	0%	
Contingent NAV						7.349	3.892	268	15%	506	238	13%	
Exploration NAV						30.364	9.269	639	36%	2.162	1.523	86%	
Risked NAV		15.546	4.820			50.319	25.767	1.776	100%	3.537	1.761	99%	
						Number of shares (m)		905					

The NAV model gives a total commercial and contingent NAV of GBp 1.137/share, which indicates that ~62% of the risked exploration value is accounted for in the share price today (30.04.2012) of GBp 1.534. To visualize the value components, a breakdown into country contribution from the overall model can be made as in Figure 4.1.

Figure 4.1 Risked NAV Distribution between countries



The distribution of the total risked NAV value clearly states the importance of single countries. Not surprisingly, Ghana represents 49% of the total value, divided between the commercial, contingent and exploration NAV. This is due to their well progressed development in Jubilee, WC3 and DWT, and out of 49% (908p/share) less than 1/3 is represented in the exploration NAV. It can therefore be concluded that Ghana is by far the most important country in terms of present valuation, which also indicates the company's dependence on the functionality within the Ghanaian operations.

Secondly, WAP represents 12% (219 p/share) of the total risked value. WAP includes, as previously described, eight countries in West Africa and South America[113]. This is clearly a value that involves higher risk than comparable NAV values, and it is important to take into account the WAP components in an investment decision. If Tullow discovers fields similar to Jubilee and Zaedyus, further de-risking can be applicable (from 20% today) which will be a positive catalyst for Tullow.

Two important assets for Tullow are Uganda and Mauritania with respectively 9% (174 p/share) and 6% (115 p/share) of risked NAV value. Uganda has net 367 mmboe in the commercial NAV, where Mauritania only has net 3 mmboe remaining in current production.

113 Mauritania, Senegal, Sierra Leone, Liberia, Ivory Coast, French Guiana, Guyana and Suriname

Mauritania is represented in the contingent NAV with over 400 mmboe net, against Uganda with approximately 185 mmboe net in exploration NAV. Even though Mauritania´s assets are not appreciable in the exploration NAV, it represents a larger reservoir value not accounted for in the model than Uganda. This implies a greater potential upside in Mauritania if Tullow were to be successful in their exploration and development of the prospects involved. This will be illustrated in part 4.3 - Upside potential.

South America is represented with the Zaedyus and Dasypus prospects in French Guiana with 5% (84 p/share) out of the total risked value. This is the first discovery that supports the theory of the WAP in finding analogue prospects in West Africa and South America. The planned E&A drilling in 2012 and 2013 will be very important for the de-risking of the area. The deeper water in South America makes it more complicated to operate, and demands a higher opex in the valuation. Tullow´s advantage is that the prospects are of similar structure as the Jubilee field, and they can therefore use this experience in the development of Zaedyus.

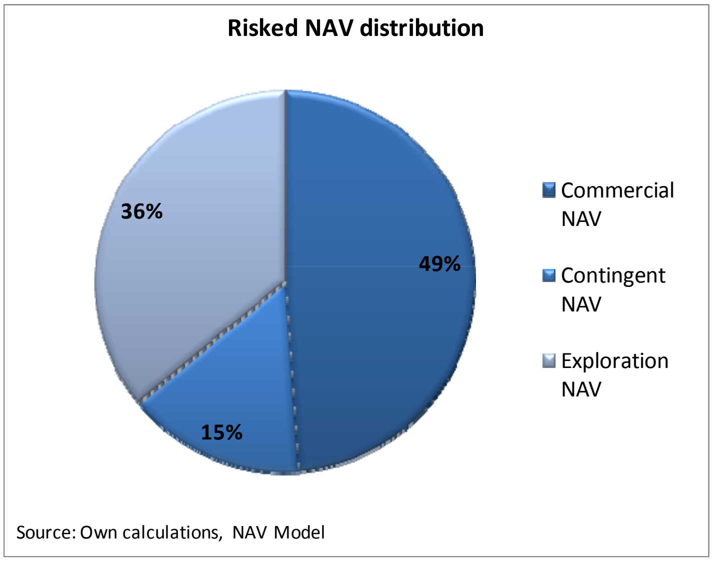
With 4% (65 p/share) Kenya is only represented in the model with a small portion of what is said to be possible levels in the area. As described, the contractors have announced that possible reservoir levels might be as high as 3-6 bnboe. However, it is too early to include these possible reserves in the valuation before further exploration and appraisal is done. If the area turns out to be comparable to the Ugandan assets, it can become a positive catalyst for Tullow with de-risking of large reserves.

The three producing countries Ivory Coast, Gabon and Equatorial Guinea represent 7% all together. This is mainly from their existing production except from Ivory Coast and Gabon which are represented in the exploration NAV each with 1,2% (20 p/share) and 0,3% (5 p/share) accordingly. The others are gathered in one cluster, representing 8% (146 p/share) divided between all three categories.

4.1.1 Value distribution

In analysing today’s share price and the components involved, it is advantageous to divide the total NAV value between the three NAV categories. This illustrates what part of the value that originates from the “safer” assets and what originates from the “riskier” assets. In Figure 4.2, the value distribution is emphasized.

Figure 4.2 Risked NAV Distribution



The NAV value of 1.776 p/share can therefore be said to include ~64% safe assets, and ~36% riskier assets. It can be discussed whether or not contingent NAV can be described as safe assets, as this includes assets that are to be produced, but with uncertainties concerning quality of the oil, reservoir levels and development progress. These factors are accounted for in the risk weighting.

When looking at an E&P company as an investment opportunity, it is commonly known that you pay for a value that might be realized in the future, either through new discoveries or an increase in production. This is also why these companies tend to be highly correlated with the oil price, and that new discoveries can be crucial for the share-price both in terms of the specific prospect, but also in de-risking similar or adjacent fields. The distribution of Tullow´s NAV value can be said to be a balanced value distribution with as much as 49% in commercial NAV which involves producing or soon to be producing assets, and 15% in contingent NAV which includes the midterm (1-3 years) prospects most likely to be developed. A factor of 36% as exploration value is common in the industry, and this ratio is expected to increase significantly during the E&A drilling in 2012 – 2013.

4.2 Component description

As explained in the introduction of the analysis, an illustration of the commercial, contingent and exploration components will be visualized. The NAV output for each part will be presented below.

4.2.1 Commercial NAV

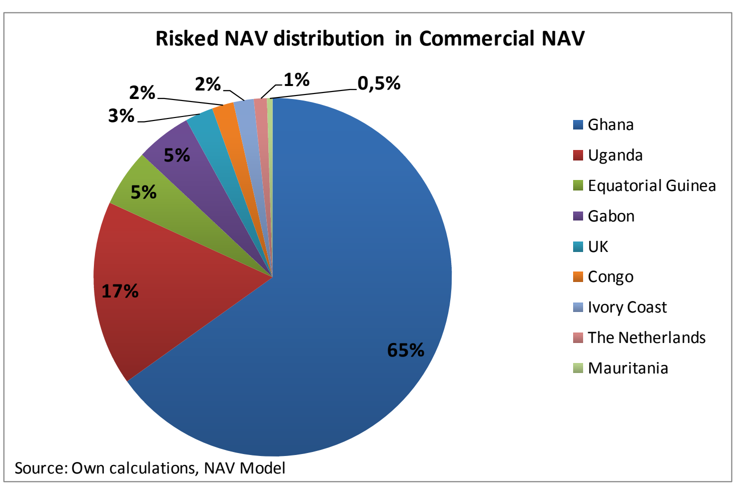
The value of the commercial NAV is straight forward to value. The prospects included in this part are all producing, except Uganda, and the output can be seen in Table 4.2.

Table 4.2 Commercial NAV Output

Net Asset Value (NAV)		P50 gross resources	P50 working interest	EV/bbl working interest	Risk weight-ing	Unrisked EV	Risked EV	Risked EV/sh	% of group value	Field WI (eq)
Country	**Field**	**mmboe**	**mmboe**	**$/boe**	**%**	**$m**	**$m**	**p/sh**	**%**	**%**
Ivory Coast	Espoir	61	13	17,5	100%	229	229	16	0,9%	21%
Ivory Coast		**61**	**13**	**17,5**	**100%**	**229**	**229**	**16**	**0,9%**	**21%**
Equatorial guinea	Ceiba	64	9	23,1	100%	210	210	14	0,8%	14%
Equatorial guinea	Okume complex	122	17	25,3	100%	440	440	30	1,7%	14%
Equatorial Guinea		**186**	**26**	**24,5**	**100%**	**650**	**650**	**45**	**2,5%**	**14%**
Gabon	All fields	52	52	12,1	100%	632	632	44	2,5%	100%
Gabon		**52**	**52**	**12,1**	**100%**	**632**	**632**	**44**	**2,5%**	**100%**
Congo	M'Boundi	88	10	25,6	100%	247	247	17	1,0%	11%
Congo		**88**	**10**	**25,6**	**100%**	**247**	**247**	**17**	**1,0%**	**11%**
Mauritania	Cinguetti	15	3	19,6	100%	65	65	5	0,3%	22%
Mauritania		**15**	**3**	**19,6**	**100%**	**65**	**65**	**5**	**0,3%**	**22%**
UK	UK North Sea gas fields (CMS & TH)	32	32	9,9	100%	318	318	22	1,2%	100%
UK		**32**	**32**	**9,9**	**100%**	**318**	**318**	**22**	**1,2%**	**100%**
The Netherlands	Nuon acquisition - producing fields	180	27	5,5	100%	150	150	10	0,6%	15%
The Netherlands		**180**	**27**	**5,5**	**100%**	**150**	**150**	**10**	**0,6%**	**15%**
Ghana UNIT	Jubilee Phase 1&1a	470	167	27,4	100%	4.356	4.356	300	16,9%	35%
Ghana UNIT	Jubilee P50 remainder - Phase 1b	205	78	18,1	100%	1.419	1.419	98	5,5%	38%
Ghana DWT	TEN	280	140	17,4	100%	2.435	2.435	168	9,5%	50%
Ghana		**955**	**385**	**21,3**	**100%**	**8.210**	**8.210**	**566**	**31,9%**	**40%**
Uganda	Ugandan Development	1.100	367	5,7	100%	2.105	2.105	145	8,2%	33%
Uganda		**1.100**	**367**	**5,7**	**100%**	**2.105**	**2.105**	**145**	**8,2%**	**33%**
Commercial NAV		**2.669**	**915**	**13,8**	**100%**	**12.606**	**12.606**	**869**	**48,9%**	**34,3%**

Ghana represents the majority of the total commercial value with ~65% (566 p/share) out of 869 p/share. All the countries included in the commercial NAV are modelled separately to find the EV/BBL. A graphically illustration of the commercial split can be seen in Figure 4.3.

Figure 4.3 Risked NAV distribution of Commercial NAV



Ghana and Uganda are the biggest contributors, with 82% out of the total commercial value. Mauritania has several prospect that are to be developed during the next years which can be seen in the contingent NAV below, which will most likely increase their commercial values in the country.

4.2.2 Contingent NAV

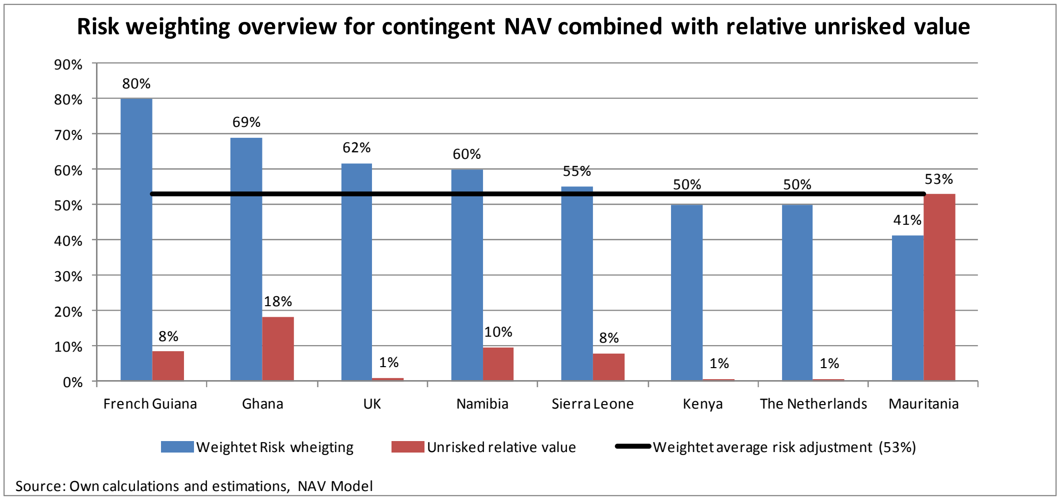
The prospects involved in the contingent NAV are the prospects that are to be developed in the midterm future. The output of the NAV model can be seen in Table 4.3.

Table 4.3 Contingent NAV Output

Net Asset Value (NAV)		P50 gross resources	P50 working interest	EV/bbl working interest	Risk weight-ing	Unrisk ed EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Field WI (eq)
Country	**Field**	**mmboe**	**mmboe**	**$/boe**	**%**	**$m**	**$m**	**p/sh**	**%**	**p/sh**	**p/sh**	**%**	**%**
Mauritania	Tiof	250	54	9,6	50%	520	260	18	1,0%	36	18	1%	22%
Mauritania	All other fields	700	350	9,6	40%	3.370	1.348	93	5,2%	232	139	8%	50%
Mauritania		**950**	**404**	**9,6**	**41%**	**3.890**	**1.608**	**111**	**6,2%**	**268**	**157**	**9%**	**43%**
Namibia	Kudu	500	155	4,6	60%	709	425	29	1,7%	49	20	1%	31%
Namibia		**500**	**155**	**4,6**	**60%**	**709**	**425**	**29**	**1,7%**	**49**	**20**	**1%**	**31%**
Sierra Leone	Mercury	75	15	18,7	50%	280	140	10	0,5%	19	10	1%	20%
Sierra Leone	Jupiter	83	17	18,7	60%	310	186	13	0,7%	21	9	0%	20%
Sierra Leone		**158**	**32**	**18,7**	**55%**	**590**	**326**	**22**	**1,3%**	**41**	**18**	**1%**	**20%**
Ghana WC3	Mahogany East Area	80	21	14,0	80%	295	236	16	0,9%	20	4	0%	26%
Ghana WC3	Teak P50	120	32	14,0	80%	443	355	24	1,4%	31	6	0%	26%
Ghana WC3	Akasa-1	32	8	14,0	80%	118	95	7	0,4%	8	2	0%	26%
Ghana UNIT	Jubilee- Associated gas + TEN	173	66	7,4	50%	492	246	17	1,0%	34	17	1%	38%
Ghana		**405**	**127**	**10,6**	**69%**	**1.349**	**931**	**64**	**3,6%**	**93**	**29**	**2%**	**31%**
Kenya	Ngamia-1 (Block 10BB)	35	18	3,5	50%	61	31	2	0,1%	4	2	0%	50%
Kenya		**35**	**18**	**3,5**	**50%**	**61**	**31**	**2**	**0,1%**	**4**	**2**	**0%**	**50%**
French Guiana	Guyane Maritime- Zaedyus	175	48	12,9	80%	623	499	34	1,9%	43	9	0%	28%
French Guiana		**175**	**48**	**12,9**	**80%**	**623**	**499**	**34**	**1,9%**	**43**	**9**	**0%**	**28%**
UK	K4	25	6	6,5	50%	36	18	1,3	0,1%	2,5	1,3	0%	23%
UK Thames	Bure N	2	1	6,5	50%	9	4	0,3	0,0%	0,6	0,3	0%	67%
UK CMS	Katy (formerly Harrison)	20	5	6,5	80%	29	23	1,6	0,1%	2,0	0,4	0%	23%
UK		**47**	**11**	**6,5**	**62%**	**74**	**46**	**3**	**0,2%**	**5**	**2**	**0%**	**24%**
Netherlands	Nuon fields incl Epidote	97	15	3,6	50%	53	26	1,8	0,1%	3,6	1,8	0%	15%
Netherlands		**97**	**15**	**3,6**	**50%**	**53**	**26**	**2**	**0,1%**	**4**	**2**	**0%**	**15%**
Contingent NAV		**2.367**	**810**	**9,1**	**53%**	**7.349**	**3.892**	**268**	**15,1%**	**506**	**238**	**13%**	**34%**

The risk weighting of the different prospects within the contingent NAV stretches from 40% - 80%, and hereby states how much of the potential value of the prospects that are accounted for. An overview of the different risk weightings can be seen in Figure 4.4.

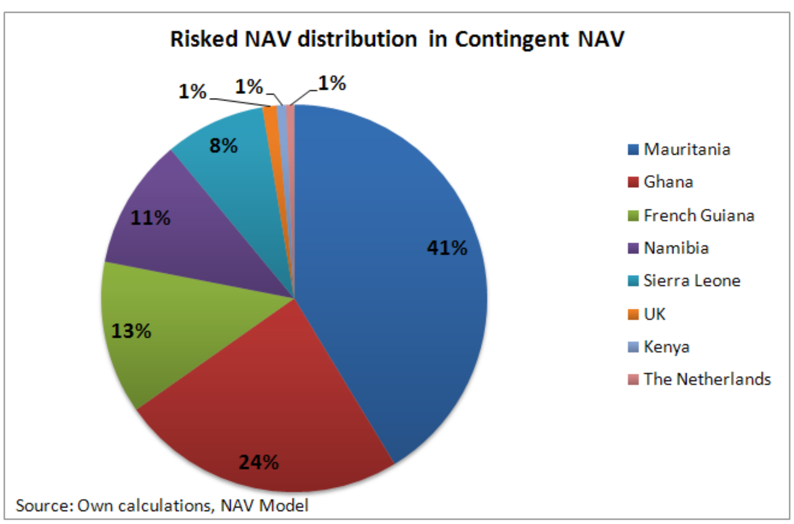
Figure 4.4 Contingent Risk Weighting overview vs. relative un-risked value



The figure illustrates the combination of the risk weighting and the relative share each country has out of the total contingent un-risked value. The blue bars represent the average risk weighting gathered from the NAV model, the red bars represent each country´s share of total contingent un-risked value, and the black line is the weighted average of 53%. Mauritania is the biggest contributor to the un-risked contingent value, and is also given the most conservative risk weighing of 41% in average. Ghana is the second largest contributor with 18% of total un-risked value with a less conservative risk weighting of 69%, because of the late stage of development.

Still with an excessive risk weighting, Mauritania is the biggest contributor among the contingent countries to the overall risked NAV value. This is illustrated in Figure 4.5.

Figure 4.5 Risked NAV distribution in Contingent NAV



Different from Figure 4.4 above, this figure shows the relative risked contribution to the overall contingent NAV value of 268 p/share. As seen, Mauritania might become an important value driver for the overall NAV with further appraisal success in the area.

If however the reservoir levels in Mauritania turn out to be only 50% of estimated P50 values of 950 mmboe, it would reduce the risked NAV with approximately 56 p/share, with the risk weighting applied. Similar, the un-risked NAV would decrease with 134 p/share.

4.2.3 Exploration NAV

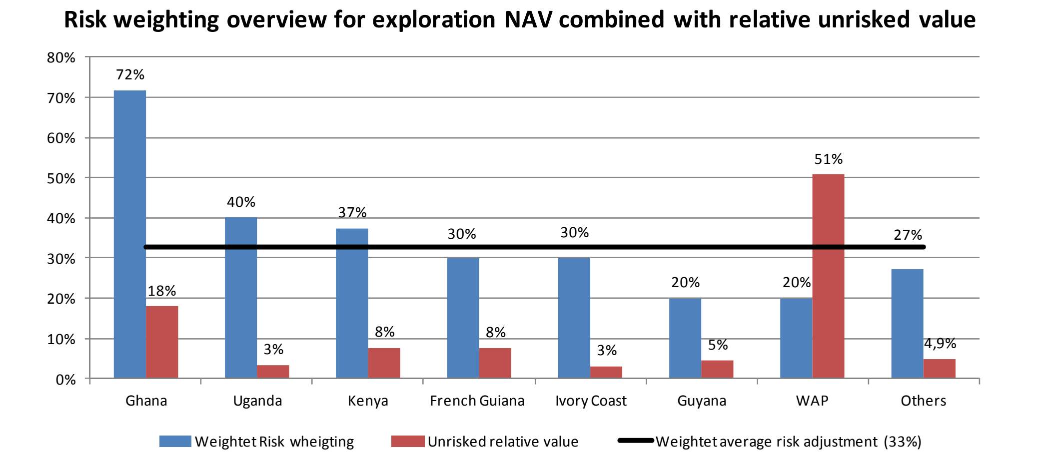
The exploration calculations are mainly based on Tullow Oil´s Fact Book 2011. It is a combination of both exploration and appraisal prospects that may result in increased reservoirs and further de-risking of existing prospects. The risk weighting is between 20% and 80%.

Table 4.4 Exploration NAV Output

Net Asset Value (NAV)		Spud date	P50 gross resources	P50 working interest	EV/bbl working interest	Risk weight-ing	Unrisked EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Field WI (eq)
Country	**Field**		**mmboe**	**mmboe**	**$/boe**	**%**	**$m**	**$m**	**p/sh**	**%**	**p/sh**	**p/sh**	**%**	**%**
Liberia	Cobalt - Strontium	4Q12	165	41	12,5	30%	515	154	11	0,6%	35	25	1%	25%
Liberia			**165**	**41**	**12**	**30%**	**515**	**154**	**11**	**0,6%**	**35**	**25**	**1%**	**25%**
Ivory Coast	Paon	2Q12	205	92	11,5	30%	603	181	12,5	0,7%	41,5	29,1	2%	45%
Ivory Coast	Kosrou	progress	265	59	11,5	30%	387	116	8,0	0,5%	26,7	18,7	1%	22%
Ivory Coast			**470**	**152**	**7**	**30%**	**990**	**297**	**20**	**1,2%**	**68**	**48**	**3%**	**32%**
Ghana DWT	Ntomme, Owo, Enyenra appraisal	In progress	400	200	17,4	80%	3.479	2.783	191,8	10,8%	239,8	48,0	3%	50%
Ghana DWT	Tweneboa Deep	3Q12	120	60	14,0	60%	838	503	34,7	2,0%	57,8	23,1	1%	50%
Ghana DWT	Sapele-1	4Q12	75	37	14,0	60%	524	314	21,7	1,2%	36,1	14,4	1%	50%
Ghana DWT	Wawa 1	2Q12	60	30	14,0	60%	419	252	17,3	1,0%	28,9	11,6	1%	50%
Ghana WC3	Teak-4	1H12	100	26	14,0	50%	369	185	12,7	0,7%	25,5	12,7	1%	26%
Ghana			**755**	**354**	**16**	**72%**	**5.630**	**4.037**	**278**	**15,7%**	**388**	**110**	**6%**	**47%**
WAP	Jubilee/Zaedyus analogues	2013	5.600	1.459	10,9	20%	15.925	3.185	219,5	12,4%	1097,5	878,0	49%	26%
West African "Jubilee" Play			**5.600**	**1.459**	**11**	**20%**	**15.925**	**3.185**	**219**	**12,4%**	**1097**	**878**	**49%**	**26%**
French Guiana	Zaedyus-2 appraisal	3Q12	170	47	12,9	30%	605	182	12,5	0,7%	41,7	29,2	2%	28%
French Guiana	Zaedyus exploratory appriasal	2Q13	270	74	12,9	30%	961	288	20	1,1%	66	46	3%	28%
French Guiana	Dasypus-1	4Q12	230	63	12,9	30%	819	246	17	1,0%	56	40	2%	28%
Guyana	Jaguar Fan System	In progress	430	129	11,0	20%	1.413	283	19	1,1%	97	78	4%	30%
Suriname	5 well campaign - Onshore Coronie	In progress	100	40	2,7	30%	107	32	2,2	0,1%	7,4	5,2	0%	40%
South America			**1.200**	**353**	**11**	**26%**	**3.906**	**1.030**	**71**	**4,0%**	**269**	**198**	**11%**	**29%**
Uganda	Ugandan exploration - various wells	2012	555	185	5,7	40%	1.062	425	29,3	1,6%	73,2	43,9	2%	33%
Uganda			**555**	**185**	**6**	**40%**	**1.062**	**425**	**29**	**1,6%**	**73**	**44**	**2%**	**33%**
Kenya	Mbawa (Block L8)	3Q12	230	46	6,0	30%	276	83	5,7	0,3%	19,0	13,3	1%	20%
Kenya	Paipai (Block 10A)	2Q12	115	58	6,0	30%	345	104	7,1	0,4%	23,8	16,6	1%	50%
Kenya	Upside potential		1.000	300	6,0	40%	1.800	720	49,6	2,8%	124,0	74,4	4%	30%
Kenya			**1.345**	**404**	**6**	**37%**	**2.421**	**906**	**62**	**3,5%**	**167**	**104**	**6%**	**30%**
Ethiopia	Sabisa	4Q12	140	70	6,5	20%	455	91	6,3	0,4%	31,4	25,1	1%	50%
Ethiopia			**140**	**70**	**7**	**20%**	**455**	**91**	**6**	**0,4%**	**31**	**25**	**1%**	**50%**
Mauritania	Sidewinder	4Q12	205	46	9,6	20%	292	58	4,0	0,2%	20,1	16,1	1%	22%
Mauritania			**205**	**46**	**6**	**20%**	**292**	**58**	**4**	**0,2%**	**20**	**16**	**1%**	**22%**
Gabon	Gnondo	4Q12	40	21	7,9	50%	131	66	4,5	0,3%	9,1	4,5	0%	53%
Gabon			**40**	**21**	**6**	**50%**	**131**	**66**	**5**	**0,3%**	**9**	**5**	**0%**	**53%**
Netherlands	K8, Sigma, Vincent	3Q12	35	11	3,6	50%	38	19	1,3	0,1%	2,6	1,3	0%	30%
Netherlands			**35**	**11**	**4**	**50%**	**38**	**19**	**1**	**0,1%**	**3**	**1**	**0%**	**30%**
Exploration NAV			**10.510**	**3.095**	**10,1**	**33%**	**31.364**	**10.269**	**708**	**39,9%**	**2.162**	**1.454**	**82%**	**29,4%**
Less exploration costs 2012							-1.000	-1.000	-69	-4%				
Net exploration NAV			**10.510**	**3.095**	**9,8**	**31%**	**30.364**	**9.269**	**639**	**36,0%**	**2.162**	**1.454**	**82%**	

The exploration NAV represents the "blue sky" scenario and these prospects are the ones that hopefully will increase the company´s reserve base, which makes the risk weighting essential. It is to be said that many of the prospects involves appraisal drilling, and not exploration drilling in "untouched" areas. In other words, the probability of success is higher, all other things being equal. Figure 4.4 illustrated the relationship between the risk weighting and the relative contribution to the contingent un-risked NAV value. The same can be illustrated for the exploration NAV as seen in Figure 4.6.

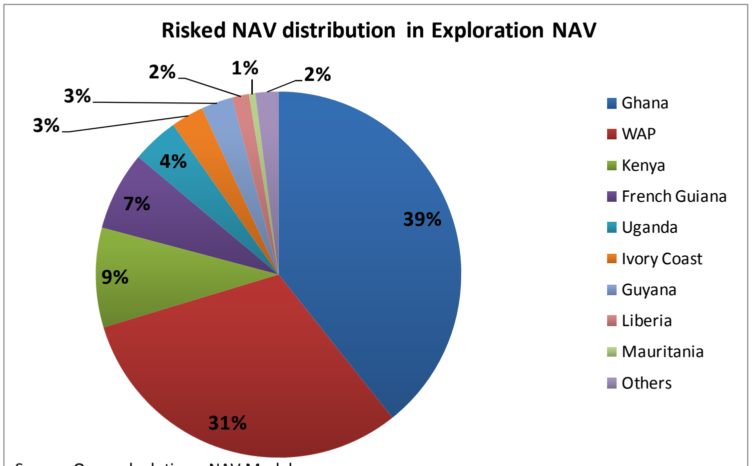
Figure 4.6 Exploration Risk Weighting overview vs. relative un-risked value



Source: Own calculations and estimations NAV Model

The average weighted risk adjustment is 33%, which is mainly pulled up by the Ghanaian development. WAP accounts for the largest un-risked value (51%), and has accordingly one of the most conservative risk-weightings of 20%. The NAV distribution can also be illustrated in terms of the exploration value contributed from each country. The illustration in Figure 4.7 shows the dependency on the respective prospects´ success.

Figure 4.7 Risked NAV distribution of Exploration NAV



Source: Own calculations, NAV Model

Even though WAP represents a significant larger un-risked value than Ghana, the risked NAV contribution from the two areas is not that different. This is because the NAV model is more sensitive to the Ghanaian development due to a lower risk weighting (less conservative) compared to the WAP development. In future valuations, it would be more accurate to split up the WAP countries, and calculate each individual value along with more provided information. (A simplified WAP allocation of the potential upside can be seen in Figure 4.12 and Figure 4.11).

4.2.4 Financial additions/subtractions

The value of the NAV components is based on each individual prospect, ignoring the overall company costs and financial items. To account for the net financial income or loss, the following posts are calculated and applied in the NAV value.

4.2.4.1 Tariff Income

To account for the tariff income, the present value of all future tariff income is calculated, and this is not included in the field model. The tariff income is mainly from the UK assets, and has increased steadily historically which supports the growth rate used of 3%. The present value is added to the NAV value and the calculation can be seen in the following equation.

$$Present\ Value\ of\ Tariff\ Income = \frac{Tariff\ Income\ 2012}{WACC - Growth} = \frac{\$\ 14{,}1m}{10\% - 3\%} = \ \$201\text{m}$$

4.2.4.2 Hedge Value

Tullow hedge part of their production and all the information concerning hedged volumes and prices are published in the Annual Report. To calculate the value of the hedge contracts, the projected oil price for 2012 – 2014 seen in Table 4.5 is used. This value is then added to the NAV value.

Table 4.5 Value of Oil and Gas Hedging

Hedging value		2008A	2009A	2010A	2011A	2012E	2013E	2014E
Brent price - unhedged	$/bbl	93	63	80	111	106	102	95
Oil price - hedged	$/bbl	71	65	83	104	117	112	105
Oil volume hedged	kb/d	19,3	17,5	14,5	19,2	34,5	25,5	12,0
Revenue impact	$m	(156)	15	14	(48)	139	94	41
Revenue impact	£m	(85)	10	9	(30)	85	58	25
Gas price- unhedged	p/th	67	31	42	58	62	67	67
Gas price -hedged	p/th	50	49	44	56	60	68	76
Gas price -hedged	$/bbl	55	47	39	54	59	66	73
Gas volume hedged	scf/d	81	49	26	44	29	12	3
Gas volume hedged	kb/d	14	8	4	7	5	2	1
Revenue impact	$m	(91)	51	2	(5)	(2)	1	1
Total revenue impact	$m	(247)	67	16	(52)	136	95	42
NPV of hedging						274		
Total hedge								
% total WI volume hedged	%	50%	44%	33%	34%	51%	28%	10%
Average hedge price	$/bbl	64	59	73	90	110	109	103

Source: Own calculations, Tullow Oil Annual Report p. 36

A gain of $274m is added to the NAV value, which is the present value of the different revenue impacts from 2012 – 2014. The value of the contracts is of course dependent on the projected oil and gas prices, and the used WACC.

4.2.4.3 Corporate costs

To account for corporate costs that are not incorporated in the different field calculations the value in 2011 is multiplied with six, which is standard in valuation of similar companies among analysts.

$$Corporate\ Costs\ (six\ times\ corp.costs\ 2011) = \$126m\ x\ 6 = \$759m$$

4.2.4.4 Net sales revenue Asian assets

As previously described, Tullow are in the process of selling their Asian assets in Pakistan and Bangladesh. After talking with a couple of analysts[114], the net amount to Tullow is estimated to be $80m which is added to the NAV value.

4.2.4.5 Net Debt

Net debt is calculated with the closing balance (net debt/net cash) from the cash flow statement of $-2,8bn ultimo 2011. This indicates that a large part of their reserved based

114 Gerry Hannigan from Goodbody Stockbrokers and Oswald Clint from Sanford Bernstein

credit facility of $ 3,5bn was drawn. This value is adjusted for the $2,9bn farm-down of the Ugandan assets in February and the estimated sale of the Asian assets of $80m which is expected to be conducted in 2012. This gives a net cash value of $164m, which is added to the NAV value.

4.2.4.6 NAV value

The final NAV value is calculated as shown in Table 4.6. The financial values described above are added or subtracted from the overall commercial, contingent and exploration NAV before the final risked NAV is provided.

Table 4.6 Combined NAV Value

Net Asset Value (NAV)		P50 gross resources	P50 working interest	EV/bbl working interest	Risk weight-ing	Unrisked EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Field WI (eq)
Country	Field	mmboe	mmboe	$/boe	%	$m	$m	p/sh	%	p/sh	p/sh	%	%
Tariff income value	PV of future post tax CF					241	241	17	0,9%	17			
Hedging value isolated	PV of future hedging profit / loss					274	274	19	1,1%	19			
Less corporate costs	6x present value					-759	-759	-52	-3,0%	-52			
(Net debt) / net cash	Adjusted 31 December 2011					164	164	11	1%	11			
Estimated net sales revenue Asian Assets						80	80	6	0,3%	6			
Net financial items						**-0,4**	**-0,4**	**-0,1**	**0%**	**-0,1**			
Core (Commercial) NAV						**12.606**	**12.606**	**869**	**49%**	**869**	**-**	**-**	
Contingent NAV						**7.349**	**3.892**	**268**	**15%**	**506**	**238**	**13%**	
Exploration NAV						**30.364**	**9.269**	**639**	**36%**	**2.162**	**1.523**	**86%**	
Risked NAV		**15.544**	**4.819**			**50.319**	**25.767**	**1.776**	**100%**	**3.537**	**1.761**	**99%**	
						Number of shares (m)		905					

As seen above, the risked NAV is calculated to be 1.776 pence per share, which is 15 % above today´s share price.

4.3 Upside potential

The upside potential described in this paragraph is not similar to the P10 upside. This is the potential "blue sky" scenario from the underlying P50 values, without any risk weighting. The potential upside given by Tullow in its fact book is purely the P10 levels. If due to successful E&A activity over the next two years some reservoirs´ P50 values would increase, then the risk weighting would also increase, leading to a higher NAV value. The model´s potential upside split is illustrated below, divided between contingent and exploration NAV.

Figure 4.9 Potential Contingent Upside distribution

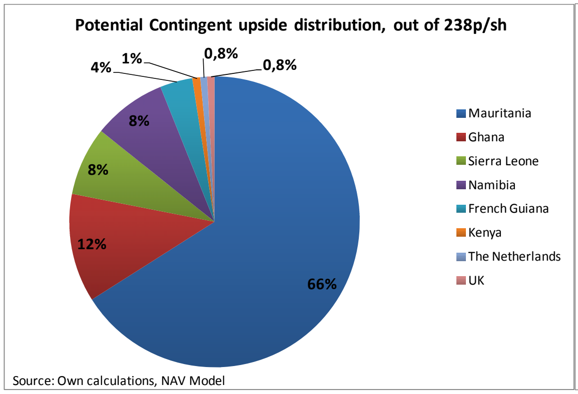
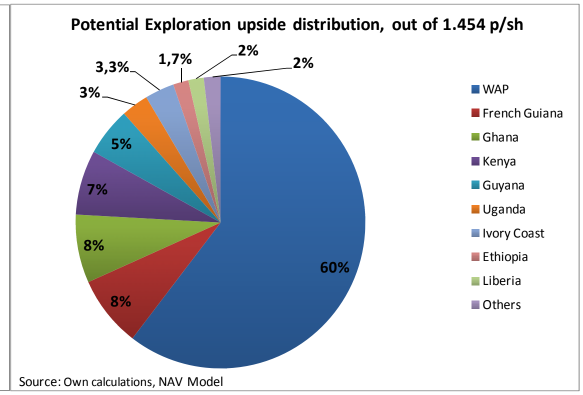
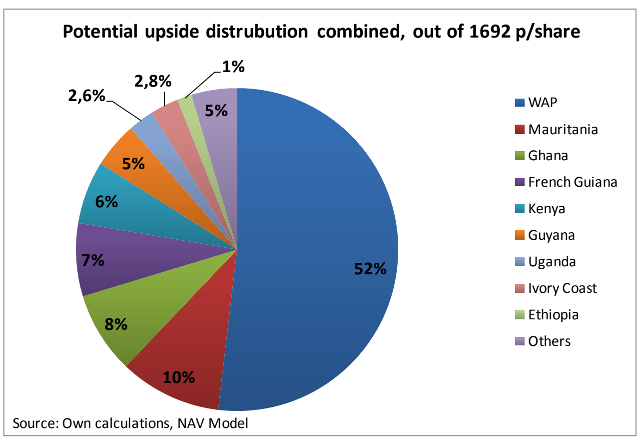


Figure 4.8 Potential Exploration Upside distribution



Both allocations have one area that stands out, Mauritania in the contingent NAV and WAP in the exploration NAV. These two areas represent a large part of the potential upside, but it is important to notice that the values are relative to the upside in pence per share, which is 238 p/share for the contingent NAV, and 1454 p/share for the exploration NAV. Figure 4.10 illustrates the overall combined potential upside based on the two models above.

Figure 4.10 Potential Upside distribution combined



As pointed out above, the relative difference is important to be aware. Figure 4.10 shows the total potential upside of 1.692 p/share distributed between the countries. WAP clearly represents the biggest potential upside with over 50% of the upside value, which is reasonable with regards to the risk weighting applied of 20%. Out of the smaller contributors, the most important catalyst is Kenya where new discoveries may multiply the registered P50 levels. Mauritania, French Guiana, Guyana and Ivory Coast are all included in WAP, and therefore represent higher potential upside than what immediately assumed. Figure 4.12 and Figure 4.11 shows the potential upside of WAP if it's divided between the included countries.

Figure 4.12 Total potential upside distribution in pence

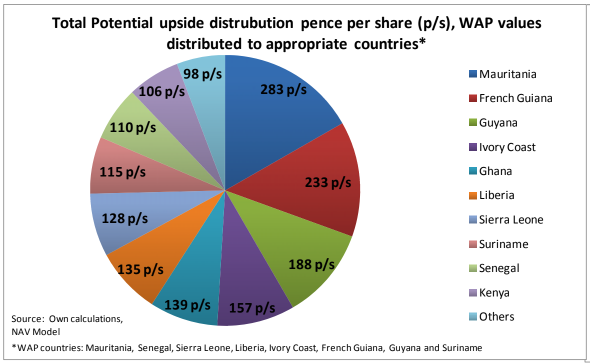


Figure 4.11 Potential upside distribution relative to total upside in pence

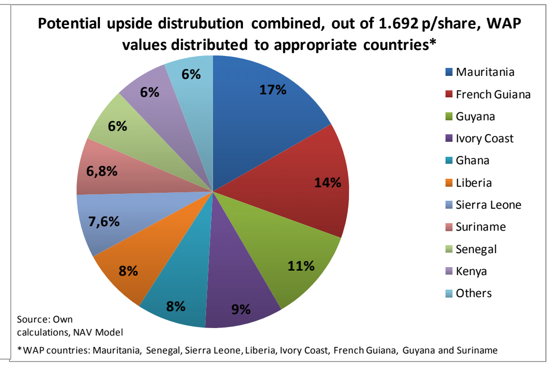
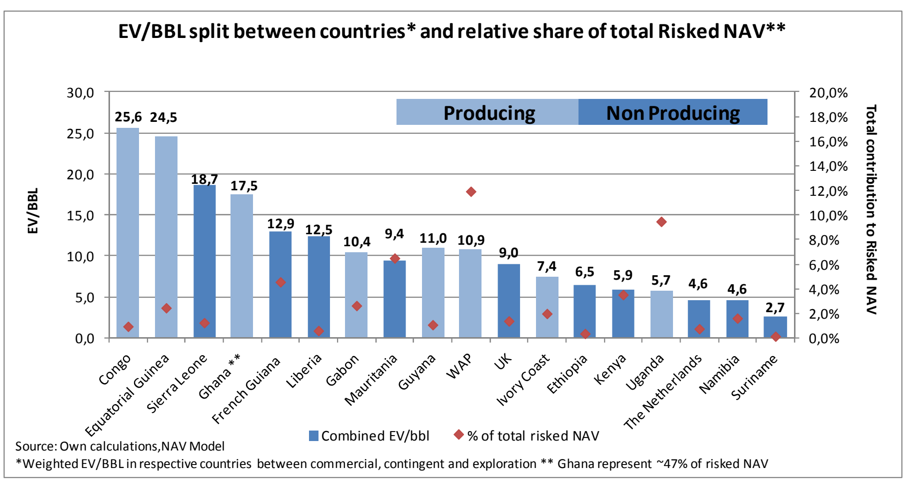


Figure 4.12 and Figure 4.11 clearly illustrates that when WAP is divided between the respective countries, the distribution of potential future value is steadier. It turns out that Mauritania is the biggest contributor in terms of potential upside followed by French Guiana and Guyana. The figures illustrate important points in terms of future potential catalysts, where South America represents over 30% of the total potential upside with 536 p/share.

4.3.1 EV/BBL distribution

As previously explained, the EV/BBL within each country is calculated with the different production agreements applicable. An area´s EV/BBL will, ceteris paribus, be higher the closer to production start it is due to the time value of money. This means that producing assets tend to have a higher EV/BBL than non-producing assets. Additionally, onshore production is less cost intensive than offshore production, resulting in higher EV/BBL values. Figure 4.13 shows an overview over the different values between the countries where Tullow is present, in addition to their respective relative share out of total Risked NAV.

Figure 4.13 EV/BBL Split between countries vs. Relative share of total Risked NAV



To find the accurate EV/BBL, each country´s total un-risked EV, commercial, contingent and exploration values, are divided with the equivalent amount of P50 WI. In this way the weighted average EV/BBL is found, and these are the levels presented above.

The bars in light blue are the countries with current production in addition to contingent and exploration values if there are any, and the bars in dark blue are the non-producing countries. Finally, the red spots represent the countries relative share of total Risked NAV, without splitting WAP between the included countries. Congo is the country with the highest EV/BBL, and this is due to its current production and the fact that it is onshore, but its relative share is only 0,9%.

Sierra Leone has the third highest EV/BBL, but the prospects Mercury and Jupiter only represent ~1,2% of the overall NAV value, and the perception of the figure can be misguiding as with Congo. It is therefore important to take the relative share into the consideration when looking at the figure. The producing countries in the lower end of the figure, UK and the Netherlands, are both subject to excessive cost control which puts pressure on the EV/BBL. The non producing countries Ethiopia, Kenya, Uganda, Namibia and Suriname are all countries where possible production lies beyond 2015, and the present value of EV/BBL is therefore additionally discounted which gives a lower value.

It is also worth looking at Uganda, which represents ~9,5% of the total Risked NAV with a low EV/BBL of $5,7. When the production start approaches, the EV/BBL will increase, which will increase the relative share Uganda represents out of the total NAV value. It is therefore a lot of values that are being "released" in the timeframe up until 2015, which will change the overall value distribution of the Risked NAV.

A categorization of the most attractive investments cannot be done immediately by looking at the figure, due to the importance concerning the knowledge of the conditions in the calculations. Many of the countries with low EV/BBL will therefore get increased levels going forward, especially along with commercialization of the different prospects.

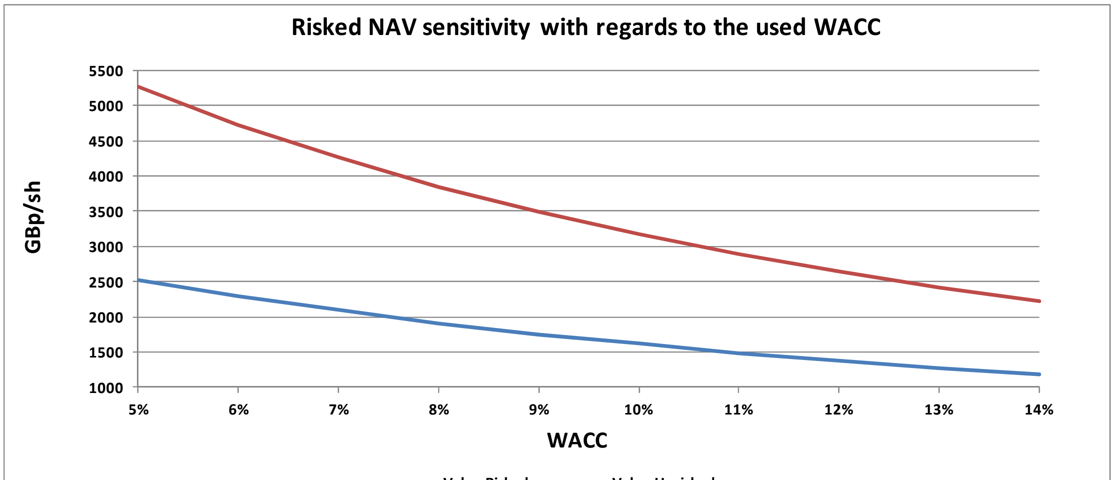
4.4 Sensitivity Analysis

There are many assumptions applied in the model to estimate the final NAV value, and hereby the target price for Tullow. Some input factors are more important than others, and these factors will be analyzed in the sensitivity analysis.

4.4.1 WACC

WACC is one of the input factors that is especially important in terms of the overall value. As discussed in part 3.3.3, the WACC is determined by factors such as the risk free rate, beta of the share, cost of debt and debt/equity levels. Figure 4.14 illustrates the NAV model´s sensitivity towards the WACC.

Figure 4.14 Risked NAV sensitivity with regards to the used WACC



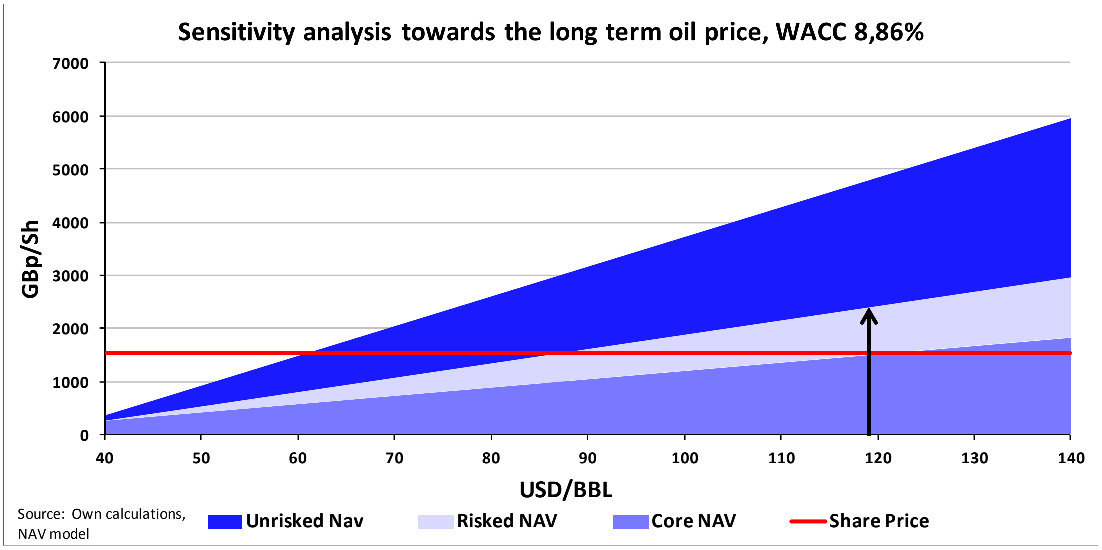
Source: Own calculations, NAV Model

The NAV value is greatly affected by the WACC, where the blue line represents the risked NAV value, or the target price, and the red line represents the un-risked value, or the blue sky scenario. The range in the risked value stretches from 1.180 p/share with a WACC equal to 14% to 2.526 p/share with a WACC of 5%. It is not possible to say exactly what WACC is the correct WACC, due to the subjectivity of the risk perception, but it is important to be aware of discount rate used, to clearly form an own opinion in terms of the investment decision.

4.4.2 Oil Price

As a second sensitivity factor, the oil price can be said to be the most important input variable in the valuation. Similar to the WACC, this input factor determines the value of the oil produced today and in the years to come. This is also why the correlation between the oil price and the share-price is as high as it is, and explains the volatility of most E&P companies' share price. A thorough sensitivity analysis is made to illustrate consequences of the final NAV value looking at oil prices between $40 – $140/bbl, as seen in Figure 4.15.

Figure 4.15 Sensitivity analysis to the long term oil price, WACC 8,86%



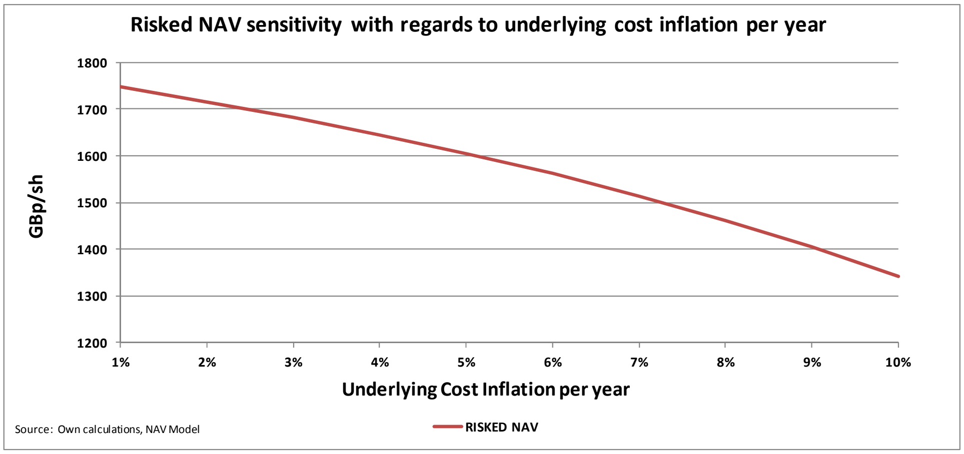
The figure does only use a long term static oil price, which is a weakness in terms of the result. However, a perspective of how the value is affected by the oil price can be interpreted. The red line shows the share price at the cut off date. At the end of April, the oil price was $119/bbl, and if this were to be the long term oil price, only parts of the risked exploration NAV, looking beyond the Core NAV is included (Commercial and Contingent).

4.4.3 Costs

The underlying cost inflation of the opex can be an important factor if the inflation increases in the countries where Tullow operates. In the model there is no underlying cost inflation going forward, mainly due to the oil companies´ continuously work to lower these costs. Tullow provide previous year´s opex in addition to present year´s opex which is the guided costs going forward.

To look at the affect from possible cost inflation, a yearly percentage increase between 1% – 10% can be applied to understand the sensitivity. Figure 4.16 illustrates this.

Figure 4.16 Risked NAV sensitivity with regards to underlying cost inflation per year



The underlying yearly cost inflation has a great effect on the NAV value, with a spread of 433 p/share. It is to be said that this scenario is based on an increase of opex in all countries operated in, which is somewhat conservative. Another important perception of the graph is the importance for Tullow to control its opex, and constantly work to decrease these costs.

4.5 Financial Analysis

The overall Profit and Loss, Balance Sheet and Cash Flow Statement can be seen in appendix 15 - 17, with further details concerning the specific posts. The financial analysis in this section is based on the accounting numbers.

In mature industries with stable revenue generation and steady growth-rate multiples, and valuation multiples and key performance ratios can be helpful in relative valuation. The problem for Tullow is their extensive growth the last years, and the expected growth going forward. Because the future earnings are expected to be multiplied, today´s key valuation multiples are extremely high compared to the forward multiples. Due to this imbalance, there is little point in comparing Tullow multiples with peers, because this will be misguiding. Table 4.7 shows the most important performance- and valuation ratios.

Table 4.7 Key Performance- and Valuation ratios

	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
KEY PERFORMANCE RATIOS										
ROIC (Before Tax)	11%	3%	2%	4%	12%	13%	15%	12%	24%	29%
ROIC (After Tax)	7,5%	1,8%	1,3%	2,4%	8,4%	8,0%	8,8%	7,4%	14,2%	17,2%
ROACE (After Tax)	6,0%	1,6%	1,5%	2,7%	8,5%	6,5%	7,7%	6,5%	12,3%	14,3%
KEY VALUATION RATIOS										
EV/DACF	34,8x	31,7x	38,0x	20,3x	9,8x	15,2x	8,3x	7,6x	5,2x	4,0x
EV/BOE (P50)	24,9x	16,6x	15,4x	9,9x	12,1x	12,1x	12,1x	12,1x	12,1x	12,1x
EV/EBITDA	30,1x	27,1x	37,8x	18,2x	7,7x	7,5x	6,0x	5,7x	3,5x	2,7x
EV/NOPLAT	106,6x	362,0x	246,8x	86,3x	17,9x	20,1x	16,1x	16,6x	7,7x	5,9x
P/E (reported)	216,1x	50,3x	806,9x	378,2x	34,3x	170,5x	33,9x	35,5x	14,2x	10,6x
P/E (diluted)	220,5x	50,3x	807,1x	378,4x	34,3x	170,5x	33,9x	35,5x	14,2x	10,6x
P/B	19,9x	10,8x	4,6x	3,7x	3,0x	2,5x	2,3x	2,1x	1,8x	1,4x

Source: Own Calculations in NAV Model

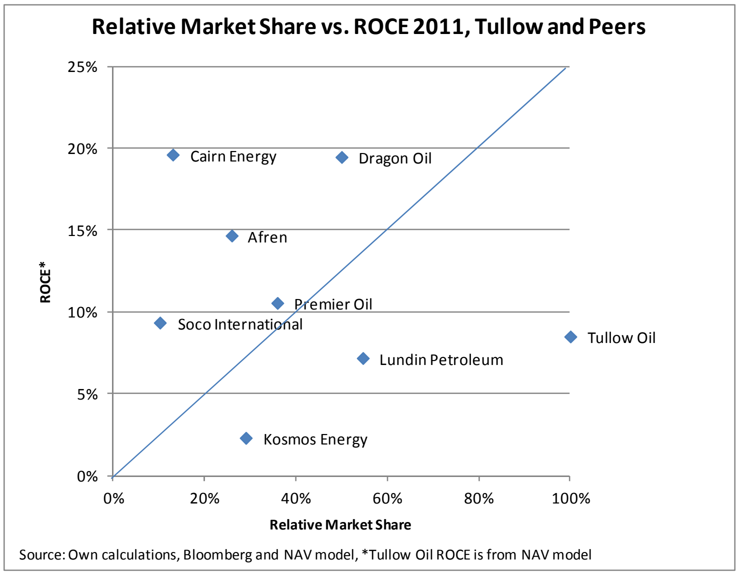
As seen in Table 4.7 above, the key valuation ratios are more normalized now than before, which of course is due to the aggressive production growth since following the production start in Jubilee commenced. Looking at the multiples, they all indicate that Tullow is expensive at today´s share price due to the expected growth going forward. This is why a multiple valuation is not emphasized further. Due to this imbalance, there is little point in using multiples in the valuation, because this will be misguiding. To illustrate this problem, a peer group comparison is done in section 4.5.4.

In capital demanding industries key performance ratios like Return on Invested Capital (ROIC) and Return on Average Capital Employed (ROACE) can be useful to use. Both values are calculated on after tax basis, and non-recurrent gains and losses are not included[115]. As seen in the table, both ratios seem to be increasing going forward which, all other things being equal, is positive. There are two reasons for this, the first being that capital investments have been high the last years and is projected to be high going forward, increasing the invested capital and capital employed. The second reason is the return from the investments is expected to be realized during the next years in form of increased production. Due to the long time frames in the industry, ROIC and ROACE will therefore not reflect the investments before the production has commenced and the performance ratios are lagging the investments with two – three years. See part 4.5.2 for further elaboration.

115 It can be discussed whether or not gains and losses from farm-downs should be included and characterized as operations, for example the farm down of Uganda in 2012. This would have increased ROACE in 2012 to 9,9%.

It gives however no meaning to look at the numbers alone due to different industry standards and it is therefore important to compare the numbers with similar companies. This can be done to a certain degree looking at ROCE, as seen in Figure 4.17. The original peers Ophir Energy, Cove Energy and Africa Oil are without revenues, and therefore not included[116].

Figure 4.17 Relative Market Share vs. ROCE for Tullow Oil and Peers, 2011



The figure shows the different ROCE[117] levels gathered from Bloomberg on 2011 accounting numbers, except from Tullow where the value is the average of 2011/2012 ROACE calculated as seen in the Table 4.7. The relative market share is found by dividing the revenue from the respective company with the market leader´s revenue, which is Tullow looking at total revenues. The problem again is that there are no direct comparable companies.

Tullow´s position as the market leader, has the third lowest ROACE of approximately 8,5%. This performance ratio is expected to decrease looking at the next 1 – 3 years due to high investments, before it is expected to increase from 2014/2015 when developing prospects commence production. Their challenge however will be to maintain the increasing ROCE in line with decreasing assets, which indicates the importance of discovering new prospects to develop.

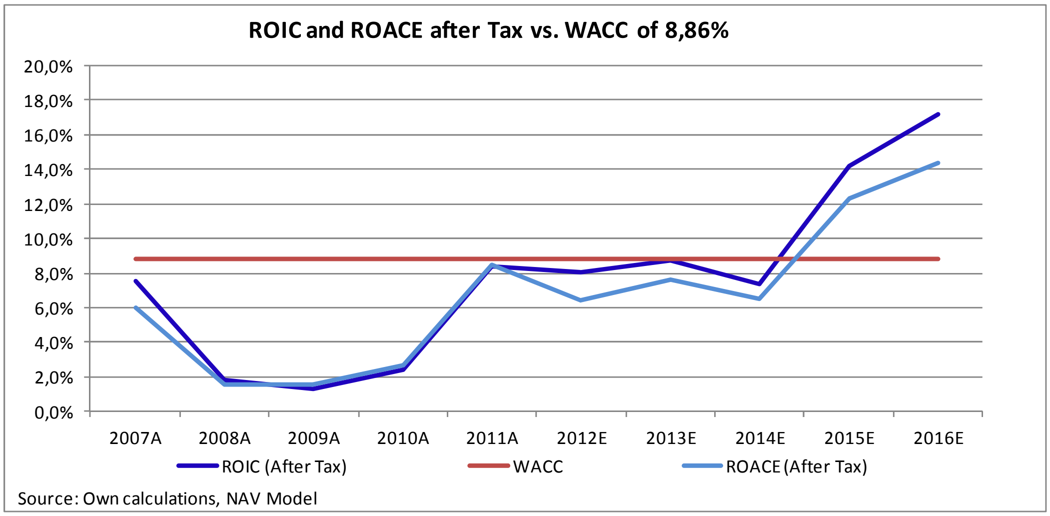
116 See appendix 14 for elaboration

117 ROACE gives a more realistic view, where average capital employed for the respective and previous year is used. This was not available in Bloomberg. It can be discussed if the different peers´ ROACE should have been calculated, but these performance- and valuation ratios are not used in the valuation, and therefore not calculated manually.

4.5.1 ROIC vs. WACC

For Tullow to generate abnormal returns, their ROIC or ROACE must be above the company´s WACC. Both performance ratios use EBIT after tax (NOPAT) adjusted for non recurring activities. In Figure 4.18 these performance ratios are compared with Tullow´s WACC.

Figure 4.18 ROIC and ROACE after Tax vs. WACC of 8,86%

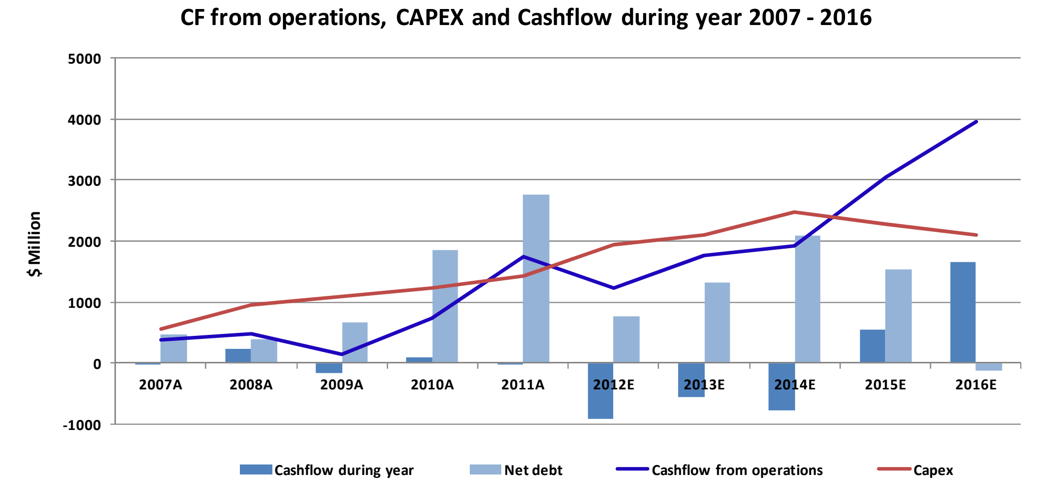


As seen from the figure, Tullow was not able to create abnormal returns to its investors in any of the historical years. This is due to their extensive capital investments and the long development time from investment to revenue generation. Even though Jubilee is producing and more prospects are being developed, it is not expected Tullow to create abnormal returns until 2015. Looking at the figure, it is clear that Tullow might go into a new stage in 2014 – 2015 where cash flow from producing assets outpace Tullow´s large capex programme, which can be seen in part 4.5.2. It is therefore important that they continue their aggressive, but thorough, exploration activity going forward, when production levels ramp up substantially in a few years, hopefully generating abnormal returns to the shareholders.

4.5.2 Cash flow vs. CAPEX

Tullow is on its way to become a self funding E&P company looking at the balance between cash inflow and cash outflow, despite their aggressive capex programme the next years. The estimates done indicate that cash flow should outpace capex during 2015 due to ramp up of production in Ghana and Uganda in the mentioned year. This can be seen in Figure 4.19.

Figure 4.19 CF from operations, CAPEX and Cash flow during year 2007 - 2016



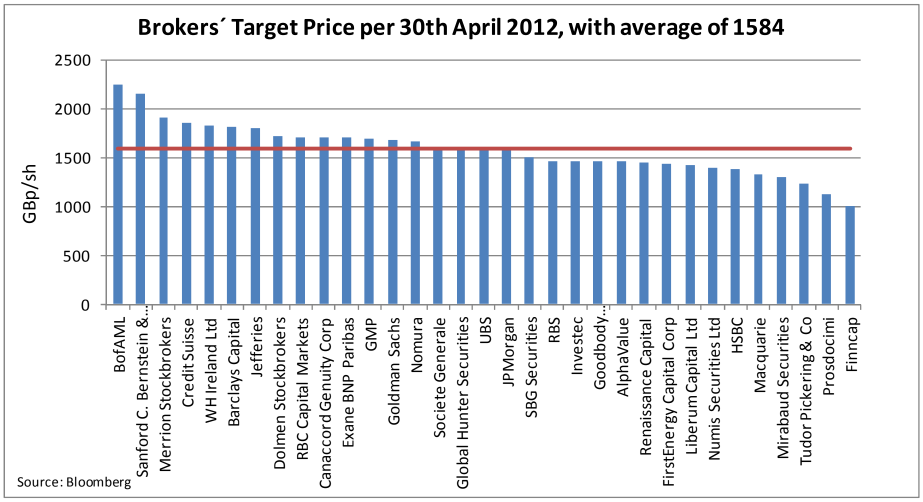
Source: Own Calculations, NAV Model

As illustrated in the figure, the cash flow during the next years increase followed by the increased production from 2015 where operating cash flow exceeds the forecasted capex. This will place Tullow in a solid financial situation, and their balance sheet is improving significantly in the next five projected years. Net debt decreased in March 2012 due to the farm-down in Uganda, but is expected to increase until the production ramp up in 2015, before having estimated net cash in 2016. Their financial situation will help the company to develop more prospects, but it is important that the excess cash does not affect the investment decisions in a negative way, so that ROACE remains high. The ramp up in cash flow from 2015 is the second game changer after Jubilee commenced production, and a result of continuously capital investments. This will be the first return, after Jubilee, from their last years´ capital spending, and there are other developing assets that will contribute to the increase in cash flow after 2015.

4.5.3 Analyst Coverage

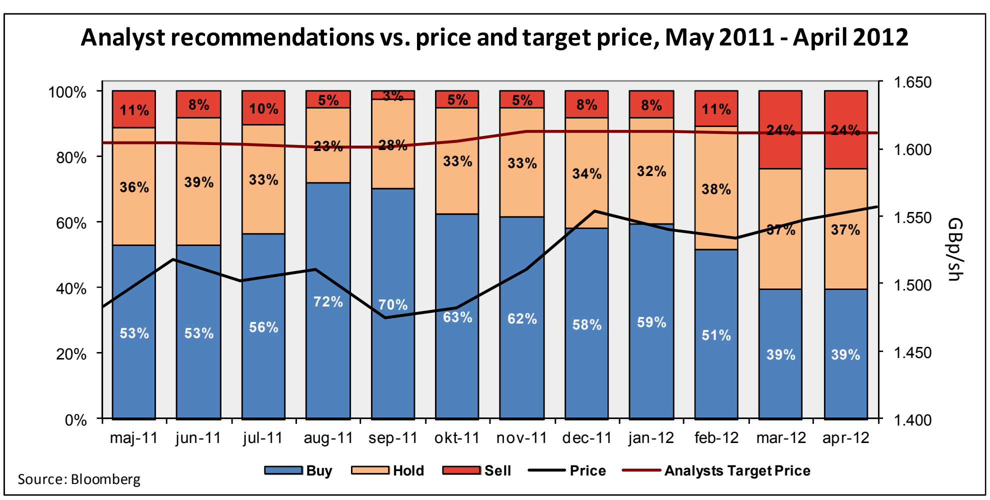
According to Bloomberg, there are approximately 33 registered analysts providing price targets on Tullow. The targets range between 1.000 and 2.240 p/share, where Finncap has the lower estimate and BofAML have the top estimate. The spread in price targets can be seen in Figure 4.20.

Figure 4.20 Broker´s Target Price as of April 30th



The spread of 1.240 p/share in the price targets illustrates the subjective perception in the valuation of the reservoir and potential future development, which is typical within the E&P sector. BofAML and Sanford Bernstein are especially worth mentioned, as both brokerage houses are well known and recognized companies. This can be a positive catalyst for the share-price development due to the investor mass they reach. It is important to not blindly trust the estimates given by analysts, as they change frequently. Larger institutional investors use the brokers in their investment decision, and during changes in the common view of the share price, it is not unusual to observe similar changes in the share-price. This is of course due to their regularly contact with the buy side[118]. A development overview of the change in broker estimation and recommendation can be seen in Figure 4.21.

Figure 4.21 Analyst recommendations vs. price and target price, May 2011 - April 2012



118 Buy side refers to the Asset Management companies that invest in, among others, public companies

As the figure states, a shift in the overall view has happened during the last 12 months, and it seems as the analysts have become more pessimistic in their view. This is most likely due to an increase in the share-price the last six months, which has reduced the potential upside. Some analysts do not believe in further upside from today´s levels before new momentum is created, either through new discoveries or faster development of existing prospects. This is supported by the drop in buy recommendations from 70% in August 2011 to 40% in April 2012. The pessimistic view can be a negative catalyst for the share price development. There are of course many analysts with different conditions in their modelling, but the statistics represents all of the major brokerage houses, and therefore a large part of the buy side, or the institutional investors.

4.5.4 Peer Group Analysis

4.6 NAV Conclusion

As previously explained in part 2.1.4, a peer group analysis can be helpful in valuing a company, if the different criteria are met. To illustrate the problems with using multiples to value E&P companies, Price to Earnings (P/E) and Price to book (P/B) on Tullow and the chosen peers are presented.

Table 4.8 Price to Earnings Ratio, 2008 - 2014

Price to Earnings Ratio		Calendarized 2008A	2009A	2010A	2011A	2012E	2013E	2014E
Company Name	Min	0,0x	16,5x	11,1x	6,6x	5,0x	5,5x	5,2x
	Max	50,3x	806,9x	378,2x	64,1x	340,6x	33,9x	35,5x
TULLOW OIL PLC*	**GBp**	**50,3x**	**806,9x**	**378,2x**	**34,3x**	**170,5x**	**33,9x**	**35,5x**
AFREN PLC	GBp		20,1x	22,7x	12,9x	5,0x	6,4x	5,2x
AFRICA OIL CORP	CAD							
OPHIR ENERGY PLC	GBp							
DRAGON OIL PLC	GBp	11,6x	16,5x	11,1x	6,6x	6,0x	5,5x	5,5x
KOSMOS ENERGY LTD	USD				64,1x	340,6x	23,4x	24,0x

Source: Bloomberg, *Own Calculations

Table 4.8 shows the Bloomberg Consensus P/E, where the historical numbers are based on accounting numbers and the projected period from 2012 – 2014 is the price ultimo April divided with consensus earnings estimates. Own calculations are used for Tullow. As seen in the table, there are no multiples for Africa Oil and Ophir Energy, and Kosmos Energy was publicly listed in 2011. It is difficult to value Tullow looking at their development in the P/E ratio. With a ration of over 800 in 2009, the company was, according multiple valuation principles, overpriced. But looking forward, the multiple declines to more normalized levels, which is due to the increase in earnings the upcoming years following the increased production.

A multiple that can be easier to use in an industry where several of the companies don't have revenue yet, is the P/B ratio. It is calculated the same way as P/E, but with shareholders equity as the denominator. This is shown in Table 4.9.

Table 4.9 Price to Book Ratio, 2008 - 2014

Price to Book Ratio		Calendarized 2008A	2009A	2010A	2011A	2012E	2013E	2014E
Company Name	**Min**	2,0x	2,1x	1,8x	1,4x	1,1x	0,9x	0,7x
	Max	10,8x	8,5x	10,0x	7,2x	6,2x	6,3x	5,8x
TULLOW OIL PLC*	**GBp**	**10,8x**	**4,6x**	**3,7x**	**3,0x**	**2,5x**	**2,3x**	**2,1x**
AFREN PLC	GBp	2,0x	2,1x	1,8x	1,4x	1,1x	0,9x	0,7x
AFRICA OIL CORP	CAD	5,9x	8,5x	10,0x	7,2x	6,2x	6,3x	5,5x
OPHIR ENERGY PLC	GBp				4,4x	4,6x	5,1x	5,8x
DRAGON OIL PLC	GBp	3,0x	2,5x	2,0x	1,6x	1,3x	1,0x	0,9x
KOSMOS ENERGY LTD	USD				4,2x	4,2x	3,2x	2,3x

Source: Bloomberg, *Own Calculations

The P/B value for Tullow is also decreasing followed by increased earnings, and hereby increasing equity attributable to shareholders. Looking at Tullow´s P/B, they are in the lower end of the scale looking forward, but it is important to have their relative size in mind, where Tullow is the largest company in terms of market capitalization.

The chosen multiples above illustrate the difficultness and the lack of reliability in using multiples in the valuation of Tullow. This is mainly due to their expected growth going forward, too little information regarding comparable companies that are in an early stage of the Production Life Cycle (PLC) and the M&A activity in the sector.

4.7 NAV Conclusion

The section above gives a thorough analysis of the NAV model output. The risked NAV is 1.776 p/share, indicating an upside of ~15% from the share-price at the cut of date. This value is allocated between commercial, contingent and exploration NAV, which classifies the prospects after where they are in the E&P cycle. The commercial value is 869 p/share, the contingent value is 268 p/share and the exploration value is 639 p/share subtracted 2012 exploration costs.

Ghana is the largest contributor to the overall NAV value with 49% of the risked NAV. The prospects in the area are therefore important for Tullow, where difficulties in production or the development of adjacent fields will have a negative effect on Tullow´s liquidity in addition to the negative share-price effect. A ramp up of the development and future production in Uganda will provide new cash flow to Tullow, and hereby spread the liquidity risk. This will be positive for the share-price.

Mauritania is the biggest contributor to the contingent NAV with 41% of the contingent value. With over 400 mmboe net to Tullow, the area can become an important cash generating asset if development of the area is commenced. On the other hand, it would have a negative effect on the share-price if the area would not be developed, or if the reservoir levels would be less than anticipated.

The countries included in the West African Play represent 31% of the risked exploration NAV and Ghana represents 39%, but the un-risked value of WAP is several times higher, indicating a larger potential upside, due to a conservative risk weighting.

Kenya is the newest discovery in Tullow´s portfolio where drilling results indicate that the prospects discovered might be several times the size of the Ugandan assets. However, it is too early to include this in the model, and only part of the potential value is included in the risked NAV. This can be an important positive catalyst if further de-risking in the area is done through appraisal drilling.

The total potential upside is 1.692 p/share where WAP represents the largest part with 52%. Mauritania is second representing 10% of the potential upside, which illustrates that the development of the area is important for Tullow both in terms of current risked NAV value, but also to create a positive momentum in the share-price. South America represents 30% of the potential upside, and parts of this value may be de-risked through the 2012 exploration drilling.

It is however important to be aware of the conservative view that has been applied in the risk weighting. If Tullow can create a similar exploration success rate as seen historically, large potential values will be “released”, affecting the share-price in a positive way.

5 Conclusion

Tullow Oil has a diverse portfolio with assets in Africa, Europe and South America. With 93% of their proven reserves located in Africa, the company is sensitive to changes in the situation on the continent. The exploration of potential oilfields is financed through cash from producing assets and a credit facility. From 2015 and forward, their need for a credit facility will diminish, which will enable Tullow Oil to become a complete self-funding E&P company.

Tullow Oil has a large asset base with more than 100 licences and activities in 22 countries. They have production in 8 countries, excluding the Asian assets, and prospects that are to be developed throughout Africa and South America. Their total reserves today amount to 1.139 million barrels of oil, and the 2011 Working Interest production was 78.200 barrels of oil per day. This generated $2,3bn in revenues, more than double compared to 2010. The Jubilee field is their largest discovery set into production to date, with total reserves of 700 million barrels of oil. Going forward, nearby prospects will be tied back to the Jubilee production, and it is expected that the production plateau will reach 120.000 barrels of oil per day within 2013. Tullow Oil is very sensitive to the development of the field and the adjacent Ghanaian prospects, due to the low risk weighting. The Net Asset Value (NAV) value will be directly affected if delays or cancellations in the area occur. Jubilee also shows that Tullow Oil can handle deep-water production and that they are able to interpret and understand the geological structure, which will be important in future development of similar prospects in the West African Play (WAP).

There are several important catalysts in terms of production and potential upside in the asset base today. The Ugandan assets are important in terms of production and future cash flow to Tullow Oil, and because such a large part of its value is included in the model, development problems will affect the NAV value directly. The three largest contributors, after the WAP, to the potential upside are Mauritania (potential upside: 173 p/share), French Guiana (potential upside: 124 p/share) and Guyana (potential upside: 78 p/share). In addition the WAP (potential upside: 878 p/share) represents the highest potential upside, which is implemented in Tullow Oil´s exploration programme for 2012 and 2013.

Tullow Oil has several competitive advantages that separate them from their peers. The first is their good track record of successful exploration drillings. Their five-year average is 75,8%, which is above the global average of 36,2% for the same period. Secondly, Tullow Oil has found valuable prospects where others have failed before them. This is because they do not drill solely based on positive seismic results, but compares prospects with similar geological areas to develop structure estimation to identify possible adjacent prospects. This has proved to be advantageous especially in concerning the countries in the West African Play.

Thirdly, Tullow Oil has shown excellent management skills through a successful M&A track record, development of complex fields (e.g. Jubilee) and active portfolio management. They urge to establish a strong relationship with the local government, and use local management and workers. This can be stabilizing due to the political instability in many of the countries where Tullow Oil operates, and it mitigates the risk of sudden expropriation. It is however important to be aware of the corruption risk, as an allegation of involvement in corruption would harm their reputation among potential investors. This political risk is incorporated in the relevant countries' risk weighting in the NAV model.

During the next five years it is expected that Tullow Oil will more than double their production volumes. Only some of this production growth is included in the share price today. Ghana and Uganda are the largest contributors for the short term production increase, and assets included in the WAP are long-term catalysts.

The risked NAV, based on the model, is 1.776 pence per share. Because of the conservative assumptions made in some of the areas with the highest potential P50 upside, and due to competitive advantages, a premium of 5% is given to the current risked NAV. This indicates a fair value of Tullow Oil´s equity of 1.865 pence per share, a potential upside of 22% from the share price April 30th 2012. It is therefore recommended to invest in Tullow Oil with an investment horizon of three to five years.

6 The thesis in perspective

Valuing one of the largest E&P companies in the world provides challenges. Not only is the business sector generally of high complexity, but with activities in over 20 countries, Tullow is a company with a highly complex asset base. An alternative to the NAV-model applied, could have been to build a Discounted Cash Flow (DCF) model. There are three main differences in building a DCF-model for the Exploration and Production (E&P) sector compared to another industry. First, there is a higher level of additional non-cash expenses to be added back to EBIT after taxes are subtracted. These are non cash-expenses like depreciation, depletion and impairment of reserves. Secondly, a 0% long-term growth should have been assumed, as the assets get depleted over time, and the reserves in the ground are finite. Finally, in the sensitivity analysis, oil price would have been the most important variable instead of revenue growth or EBITDA margins.

Even adjusting for these differences, there are three additional reasons why an ordinary DCF-model would not be precise enough. First, E&P companies normally have large growth opportunities going forward, which makes them much more dependent on the terminal value than companies in other industries. To solve for this problem, we could have used a longer forecasting period, but then the amount of work would almost be the same as with a Net Asset Value (NAV) model. Secondly, E&P companies have high capex requirements, which reduce Free Cash Flow (FCF) and may result in a declining or negative FCF. Third, there is a high demand for details in projecting the different prospects, which would have had to be done regardless of the model used.

Considering the issues with building a DCF-model, we feel comfortable that choosing the NAV-model was correct. One of the assumptions in the NAV model is that the company never increases its existing reserves beyond what is expected today, and there is no additional capex in future years beyond what is needed to develop the current estimated reserves. Another important difference between the two models is that you build a NAV-model on the asset level, while a DCF-model is done at the corporate level with fewer details. It is also to be said that all of the analysts talked with, use a NAV model in their valuations of E&P companies.

The NAV model we have developed and built includes all the public known parameters Tullow has in their daily operation. The assets are separately valued with own DCF's before they are added together to find the fair value of the company. We also believe that the allocation between commercial, contingent and exploration NAV gives the reader an understanding of the different risk factors in a better way than with a DCF-model. The final value is of course dependent on many subjective factors, but we feel comfortable in our arguments throughout the thesis for the specific estimations and assumptions that are applied. It can be discussed whether or not it is necessary with the high level of details, but in a company with such a complex asset base, we found it essential to look into each country to fully understand their operations.

As the thesis is written as an investment case aimed at potential investors, it can be discussed if it is necessary to include the simplified introduction to the sector in the beginning of the thesis. As a dual audience (both BankInvest and the academic evaluators) will read the investment case, we decided to include this explanatory part to be sure the reader has the required understanding of the business and its terminology, before looking further into Tullow itself.

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Specification: http://www.tullowoil.com/files/pdf/pres05/cmsarea.pdf

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APPENDIX TULLOW OIL INVESTMENT THESIS

Table of Contents

Appendix 1 - Figure and Table overview

Table overview

Appendix 2 - Abbreviations and glossary

Abbreviations:

Bbl	Barrels of oil (reserves)
Bbll	Billion barrels (reserves)
Boe	Barrels of equivalents (reserves)
Bnboe	Billion barrels of equivalents
Bopd	Barrel oil per day (production)
Boepd	Barrels of equivalents per day (production)
Capex	Capital expenditures
DCF	Discounted Cash Flow
E&A	Exploration and Appraisal
E&D	Exploration and development
E&P	Exploration and production
FPSO	Floating Production Storage and Offloading
FEED	Front-End Engineering and Design
GBp/share	Pence Per Share
IOC	Integrated Oil Companies
M&A	Mergers and Acquisitions
MoU	Memorandum of Understanding
Mmbo	Million barrels of oil
Mmboe	Million barrels of equivalence
Mmscfd	Million standard cubic feet per day (used for gas production)
NAV	Net Asset Value
P/share	Pence Per Share
PLC	Product Life Cycle
PSA	Production Sharing Agreement
PSC	Production Sharing Contract
WCTP	West Cape Three Points
WI	Working interest

Glossary on next page.

Glossary:

Bopd gross	Gross bopd/production is the total production on the field. Net production is Tullow´s share of the gross production.
Entitlement factor	The respective company's share of the revenue
Farm-down	Selling interests of a field/area
Farm-in	Buying interests of a field/area
FEED	Front-End Engineering and Design plan: Part of the tenders sent out to the suppliers (drilling, seismic, infrastructure companies etc) to obtain qualified offers on projects.
First-oil/First-gas	Term used for first production of oil in a field. Ex: First-oil in 2013, means that the field will commence producing in 2013.
Tie-backs	Connection between new oil and gas discoveries and an existing production facility.
Gross bopd	Gross production is the total production on the field. Net production is Tullow´s share of the gross production
P10	The reserves and/or resources estimates have a 10 % probability of being met or exceeded (also referred to as possible reserves)
P50	The reserves and/or resources estimates have a 50 % probability of being met or exceeded (also referred to as probable reserves)
P90	The reserves and/or resources estimates have a 90 % probability of being met or exceeded (also referred to as proven reserves)
Plateu production	The point where the maximum rate of production is reached. Also referred to as Peak production or steady state.
WI	Working interest is the respective company's share in the oil field.

Appendix 3 - Drilling day rates

FLOATING RIGS			
Rig Type	**Rigs Working**	**Total Rig Fleet**	**Average Day Rate**
Drillship < 4000' WD	7 rigs	8 rigs	$219,000
Drillship 4000'+ WD	59 rigs	75 rigs	$459,000
Semisub < 1500' WD	9 rigs	15 rigs	$249,000
Semisub 1500'+ WD	61 rigs	92 rigs	$301,000
Semisub 4000'+ WD	96 rigs	109 rigs	$408,000

JACKUP RIGS			
Rig Type	**Rigs Working**	**Total Rig Fleet**	**Average Day Rate**
Jackup	1 rigs	1 rigs	$140,000
Jackup IC < 250' WD	34 rigs	54 rigs	$73,000
Jackup IC 250' WD	41 rigs	62 rigs	$77,000
Jackup IC 300' WD	87 rigs	132 rigs	$87,000
Jackup IC 300'+ WD	128 rigs	155 rigs	$150,000
Jackup IS < 250' WD	6 rigs	9 rigs	--
Jackup IS 250' WD	7 rigs	9 rigs	$75,000
Jackup IS 300' WD	3 rigs	5 rigs	$60,000
Jackup IS 300'+ WD	1 rigs	3 rigs	$70,000
Jackup MC < 200' WD	3 rigs	11 rigs	$36,000
Jackup MC 200'+ WD	11 rigs	23 rigs	$66,000
Jackup MS < 200' WD	2 rigs	3 rigs	--
Jackup MS 200'+ WD	7 rigs	15 rigs	$48,000

OTHER OFFSHORE RIGS			
Rig Type	**Rigs Working**	**Total Rig Fleet**	**Average Day Rate**
Drill Barge < 150' WD	20 rigs	39 rigs	--
Drill Barge 150'+ WD	6 rigs	9 rigs	--
Inland Barge	34 rigs	76 rigs	$56,000
Platform Rig	141 rigs	251 rigs	$43,000
Submersible	0 rigs	5 rigs	--
Tender	24 rigs	33 rigs	$128,000

Source: www.rigzone.com - Offshore Rig Day Rates

Appendix 4 - M&A track record

Acquisions

- 2000: Southern North Sea Assets, acquired from BP for $398m (£200m)
- 2004: Energy Africa, acquired for $529m (£276m)
- 2005: Schooner & Ketch fields, acquired from Shell & ExxonMobil for $345m (£200m)
- 2005: Angola Block 1 – 15% farm-in acquired from Sonangol P&P
- 2005: Hewett field unit area – Additional 13% acquired from Petrofac
- 2007: Hardman Resource, acquired for $1,1bn
- 2010: Heritage Oil Uganda assets, acquired for $1,45bn
- 2010: East African Rift Basin of Kenya and Ethiopia, 50% farm in acquired from Africa Oil PLC
- 2011: Nuon E&P, acquired for $378m from the Vattenfall Group
- 2011: WCTP (+3,5%) & Jubilee (+1,75%), acquired the Ghanaian interests of EO Group Ltd for $305.

Disposals

- 2008: Disposed of 11% interest in the onshore M'Boundi field to Korea National Oil Company for $435m
- 2008: Disposed of interests in 10 CMS Area block to Venture Production PLC for $45m
- 2008: Disposed of 52% stake in Hewett (North Sea) to Eni for $265m
- 2009: Farm-down of 25% interest in French Guiana acreage to Total
- 2011: Farmed-down 30% interest in Block 47 in Suriname to Statoil
- 2012: Farm-down of 67% of its Uganda interests to CNOOC Ltd. And Total for a consideration of $2.9bn

Appendix 5 - Organizational structure

Board of Directors

Non-executive directors	
Chairman	Simon Thompson
Senior Independent Director	Steven McTiernan
Non-executive director	David Bamford
Non-executive director	Ann Grant
Non-executive director	Tutu Agyare
Non-executive director	Steve Lucas

Executive Directors	
Chief Executive Officer	Aidan Heavey
Chief Financial Officer	Ian Springett
Chief Operating Officer	Paul McDade
Exploration Director	Angus McCoss
General Counsel & Company Secretary	Graham Martin

Board Committees

Audit Committee	Nominations Committee	Remuneration Committee
▪ Steven McTiernan	▪ Aidan Heavey	▪ Simon Thompson
▪ Ann Grant	▪ Simon Thompson	▪ Steven McTiernan
▪ Tutu Agyare	▪ Steven McTiernan	▪ David Bamford
▪ Steve Lucas	▪ Ann Grant	▪ Tutu Agyare
		▪ Steve Lucas

Senior Management Committee	
Head of Corporate Planning & Economics	Pete Dickerson
General Manager Exploration	Chris Flavell
Regional Business Manager Europe, Asia and North America	Claire Hawkings
Regional Business Manager South & East Africa	Martyn Morris
Chief Human Resources Officer	Gordon Headley
Group Commercial Manager	Mike Simpson
General Manager Finance	Julian Tedder
Head of Risk & Marketing	Brian Williams

In-country management	
Uganda	Brian Glover
Ghana	Dai Jones
Angola	Brian Kay
Bangladesh	Richard Lee
Mauritania	Kemai Mohamedou
Namibia	Peter Owens
Dublin	Ian Dunleavy
Gabon	David Roux
Cape Town	Bill Torr
Ivory Coast	Franco Uliana
Pakistan	Muzaffar Virk
Senegal	Awa Wane
Tanzania	Nick Woodall-Mason

Appendix 6 - Drilling overview 2011

Drilling program 2012

2011 Discoveries			2011 Dry wells		
	Name	Country		Name	Country
1	Tweneboa-3	Ghana	1	Gharabi-1	Mauritania
2	Tweneboa-3A	Ghana	2	Muscovite-1	Netherlands
3	Cormoran-1	Mauritania	3	Banda-1	Ghana
4	Nsoga-2	Uganda	4	B'Oba-1	Gabon
5	Teak-1	Ghana	5	Makore-1	Ghana
6	Enyenra-2A	Ghana	6	Jobi-East-5	Uganda
7	Kigogole-6	Uganda	7	Foxtrot	UK
8	Teak-2	Ghana	8	Montserrado-1	Liberia
9	Tweneboa-4	Ghana	9	Nkongono-1	Gabon
10	Ngege-2	Uganda			
11	Jobi-East-1	Uganda			
12	Mpyo-3	Uganda			
13	Limande-7	Gabon			
14	Jobi-2	Uganda			
15	Gunya-A	Uganda			
16	Cameron	UK			
17	Akasa-1	Ghana			
18	Zaedyus	French Guiana			
19	Enyenra-3A	Ghana			
20	Jobi-East-2	Uganda			
21	OMOC-N-502	Gabon			
22	Teak-3A	Ghana			
23	Onal 1501 (Onal-We	Gabon			
24	Onal-1701	Gabon			
25	Maroc-Nord-102	Gabon			
26	Tchatamba South	Gabon			

Appendix 7 - Key statistics: West & North Africa

12 month exploration and appraisal program

Country	Block	Prospect	Interest	Spud Date
Côte d'Ivoire	CI-105	Kosrou-1	22.37%	In progress
	CI-103	Paon-1	45% (op)	Q2 2012
Gabon	Kiarsseny	Gnondo-1	52.78% (op)	Q4 2012
Ghana	Deepwater Tano	Ntomme-2A DST	49.95% (op)	In progress
	Deepwater Tano	Owo-1RA and DST	49.95% (op)	In progress
	Deepwater Tano	Enyenra-4A	49.95% (op)	In progress
	Deepwater Tano	Wawa-1	49.95% (op)	Q2 2012
	Deepwater Tano	Tweneboa Deep-1	49.95% (op)	Q3 2012
	Deepwater Tano	Sapele-1	49.95% (op)	Q4 2012
	West Cape Three Points	Teak-4	26.40%	H1 2012
Liberia	LB-15/16/17	Strontium-1	25%	Q4 2012
Mauritania	Various	1 Exploration Well	Various	Q4 2012
Sierra Leone	SL-07B-11	Mercury-2A	20%	In progress

Key Producing assets

Country	Asset	Interest	2011 Production	2012 Forecast	Fiscal Regime
Congo (Brazz)	M'Boundi	11%	3.000	2.400	PSC
Côte d'Ivoire	Espoir	21.30%	3.750	3.000	PSC
Equatorial Guinea	Ceiba	14.25%	2.850	3.400	PSC
	Okume	14.25%	10.200	6.900	PSC
Gabon	Tchatamba	25%	3.100	3.400	PSC
	Niungo	40%	3.000	2.500	Tax
	Etame Complex1	7.50%	1.600	1.300	PSC
	Others	-	5.000	5.800	Various
Ghana	Jubilee	35.48%	23.500	28.400	PSC
Mauritania	Chinguetti	19.01%2	1.400	1.300	PSC
Total Africa			**57.400**	**58.400**	

Development opportunities

Country	Developments	Sanction Decision	First Production	No. Of Wells	Status
Congo (Brazzaville)	M'Boundi Field Re-development		Producing	10+ wells p.a	Continued infill drilling and addition of water injector wells. Water injection upgrade completed in 2011.
Côte d'Ivoire	Acajou appraisal	2014	2016	1-2	Satellite discovery near Espoir field.
	Espoir Infill Drilling		Q4 2012	8-11	Well locations and quantity being finalised for 2H 2012 drilling.
Equitorial Guinea	Ceiba infill drilling		Q2 2012	3 WO + 8	Workovers and infill drilling commenced January 2012.
	Deep water Okume Complex Infill drilling	Q3 2012	Q3 2013	8	Tender assisted drilling unit to drill 8 wells from Echo and Foxtrot platforms.
	Shallow water Okume Complex Infill drilling	2013	2014	4-10	Jackup drilling rig to drill infill wells on Elon field.
Gabon	Ebouri/Avouma (Etame complex)		Q3 2012	3	Additional 3 horizontal producers to drill in Q2-Q4 2012, plus appraisal wells on Etame SE.
	Echira Infill	Q3 2012	Q4 2012	1	Infill drilling scheduled for Q4 2012.
	Limande Infill	Q2 2012	Q3 2011	2-4	Two further horizontal producers planned for 2012, with potential for up to 4 further wells in 2013-4, including pilot gas injection scheme.
	Niungo Infill	Q2 2012	Q4 2011	1 - 3 prod + 2 USRs	One Niungo redrill and 2 ultra short radius (USR) to commence drilling Q3 2012. Additional 2 horizontal wells likely to be drilled in Q4 2011.
	Onal- Maroc Nord Development		Producing	16 wells per year	Onal infill drilling and Maroc Nord appraisal Phase 2 in progress. Maroc Nord first oil in Q2 2011.
	Tchtamba -Azile and Anguille developments		Q2 2012	2-3	One Azile producer to spud in Q1 2012. Either 1 or 2 further wells in Q3-4 2012, depending upon outcome of Anguille formation production pilot in Q2 2012. Fuel gas supply line to be commissioned Q2 2012.
	Tsiengui		Producing	> 40 prod	Phase 2 drilling commenced Q2 2011 (3 year program). Gas injection scheme being implemented.
	Turnix	Q1 2012	Producing	2	First infill well completed Q4 2011. Two further infill wells scheduled for Q2-4 2012.
Ghana	Jubilee Phase 1a		2012	8	Approved by Government of Ghana. Infill wells using existing and minor additional subsea infrastructure. Designed to raise field recovery and extend FPSO plateau.
Jubilee Full Field	2013 onwards	2014-20	10-15		Incremental development consisting of additional infill wells and further subsea infrastructure
West Cape Three Points (Teak, Mahogany-East, Akasa)	2013	2016-21	4-6		Teak appraisal work in 2012 continues; pending outcome either a subsea tie-back to Jubilee or stand-alone project expected. Mahogany-East & Akasa remain as likely subsea tie back to Jubilee feasible when ullage available â€“ earliest anticipated in 2016
	Tweneboa/Enyenra/ Ntomme (T.E.N)	2012	2015	23-25	Plan of Development (PoD) expected to be submitted to Government of Ghana in the third quarter of 2012
Mauritania	Banda	2012	2014/15	4	Conceptual work near complete. Commercial discussions on-going with Government. Initial oil production proposed followed by gas cap blowdown.

Appendix 8 - Key statistics: South & East Africa

Key activities	Countries	Licences	Acreage (sq km)	Producing fields	Emloyees
E D P	15	58	222,018	19	506

12 month exploration and appraisal programme

Country	Block	Prospect	Interest	Spud Date
Ethiopia	South Omo	Sabisa-1	50% (op)	Q4 2012
Kenya	10BB	Ngamia-1	50% (op)	In progress
	10A	Paipai-1	50% (op)	Q2 2012
	L8	Mbawa-1	15% + 5%#	Q3 2012
Uganda	EA-1	Jobi-East - 2 wells	33.33%	2012
	EA-1	Mpyo - 3 appraisal wells	33.33%	2012
	EA-1	Ondyek-A	33.33%	Q2 2012
	EA-1	Raa-A	33.33%	Q3 2012
	EA-1	Omuka-A	33.33%	Q3 2012
	EA-1	Alwala-A	33.33%	Q4 2012
	EA-1	Rii South-B	33.33%	Q4 2012
	EA-2	Ngege - 4 appraisal wells	33.33% (op)	In progress
	EA-3A	Kanywataba-1	33.33%	2012

Development opportunities

Country	Developments	Sanction Decision	First Production	No. of wells	Status
Namibia	Kudu	2012	2015-2016	3-4	Kudu gas to power project concept studies completed. Commercial discussions with NamPower.
Uganda	Early Commercialisation Project (Nzizi Gas Field (IPP), Mputa oil & Waraga oil)	2012	2013	10+	Appraisal drilling will commence in Q1 2012 with first oil/gas expected in 2013.
	Basin Wide Development	2013	2016-2017	200+	A basin wide development plan is being prepared by the new partnership incorporating upstream development across the 3 Blocks, including refining and export infrastructure.

Appendix 9 - Key statistics: Europe, South America & Asia

Key activities	Countries	Licences	Acreage (sq km)	Producing fields	Emloyees
E D P	7	47	57,793	38	154

12 month exploration and appraisal program

Country	Block	Prospect	Interest	Spud Date
Netherlands	K8	K8-FC-W (308)	9.95%	Top hole drilled
	L13	Sigma-1	9.95%	Q3 2012
	E11	Vincent-1	30% (op)	Q4 2012
French Guiana	Guyane Maritime	Zaedyus-2 appraisal well	27.50%	Q3 2012
	Guyane Maritime	Zaedyus exploratory appraisal		2013
	Guyane Maritime	Dasypus-1l	27.50%	Q4 2012
Guyana	Georgetown Block	Jaguar Fan System	30%	In progress
Suriname	Coronie	5 well campaign	40%	In progress
Pakistan	Kohat	Jabbi	40%	In progress

Key producing assets

Country	Asset	Interest	2011 Production	2012 Forecast	Fiscal Regime
Netherlands	Nuon Assets4	4.1 - 22.5%	3000	6800	
UK	CMS Area3	14.1-100%	11500	10700	Tax
	Thames Area	50-100%	1000	1500	Tax
Bangladesh	Bangora	30%	5200	4500	PSC
Pakistan	Shekhan-1	40%	100	100	-
Total			**5300**	**4600**	

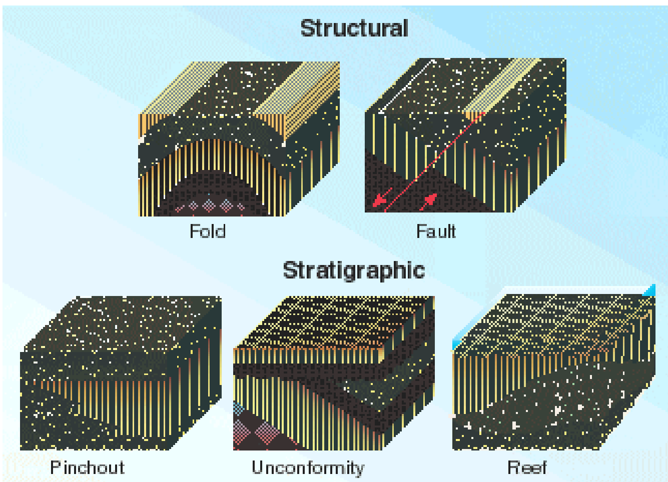
Development opportunities

Country	Developments	Sanction Decision	First Production	No. of wells	Status
Netherlands	JDA wells		2011/12	3	NAM operated wells using swift rig and back-to-back drilling.
	K18-G1		March 2012	1	Wintershall well now under production
UK CMS Area	Katy (Harrison)		2H 12	1	Under construction
	Further Schooner & Ketch wells; K-10 y drilling Q1 2012				
Bangladesh	Bangora Phase 3	2012	2012	n/a	Installation of compression to maintain plateau production at 120 mmscfd and increase recovery. Timing under review given good field performance.
Pakistan	Shekhan	2012	2013	TBC	Possible appraisal or development decision following Shekhan Extended Well Test.

Appendix 10 - Stratigraphic and Structural traps

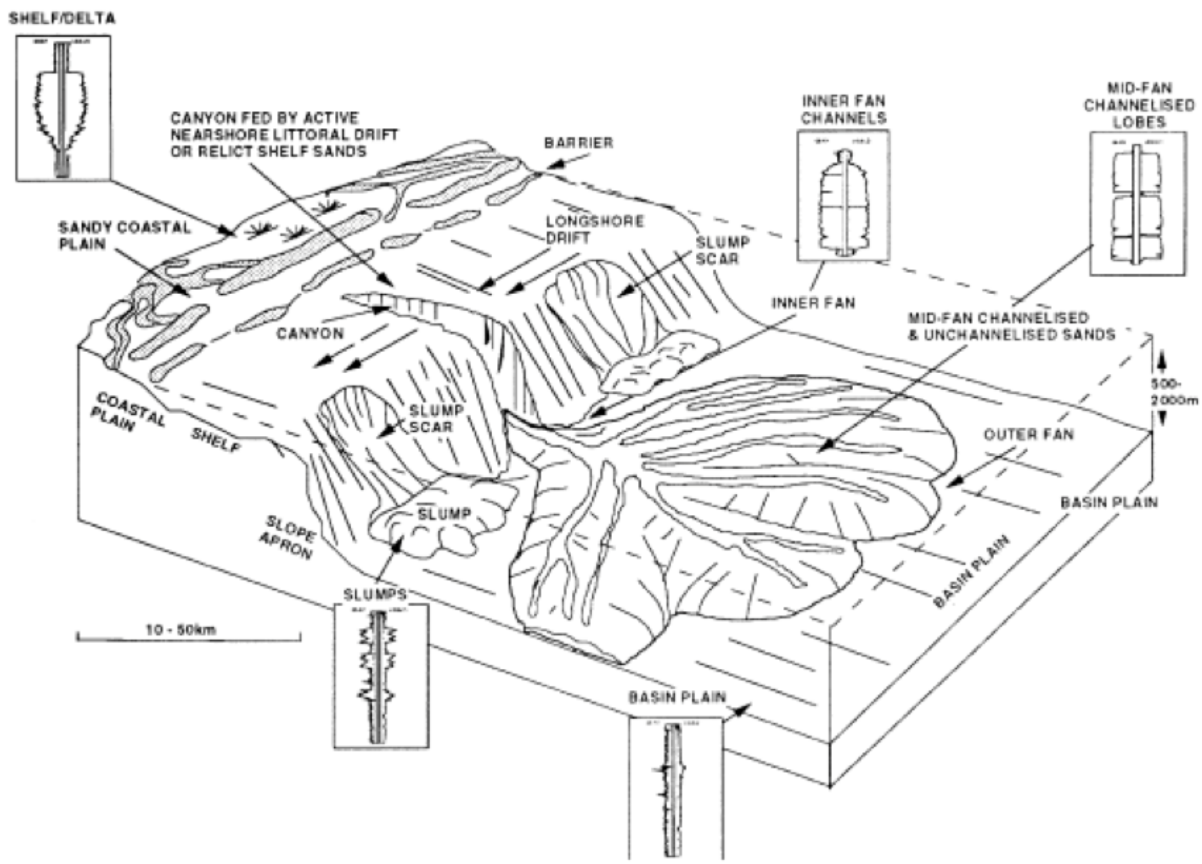
Stratigraphic traps are a variety of sealed geologic container capable of retaining hydrocarbons, formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

Structural traps consist of geologic structures in deformed strata such as faults and folds whose geometries permit retention of hydrocarbons.



Appendix 11 - Zeadyus fan structure

The figure below illustrates a "sub-marine" fan structure similar to the one discovered in the Zaedyus prospect.



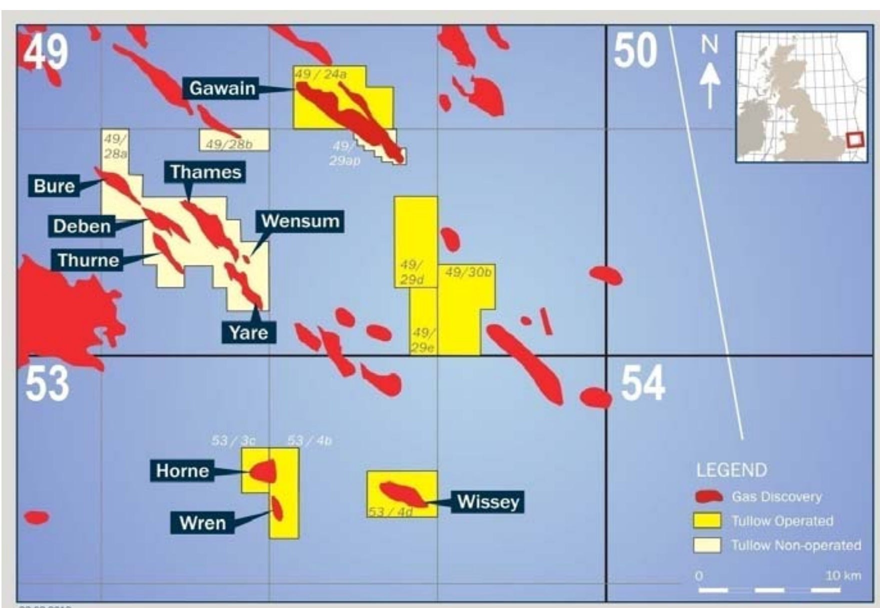
Source: Bernstein: The birth of a Super-E&P

Appendix 12 - UK assets

Thames Area - EDP

Source: Map Book 2012

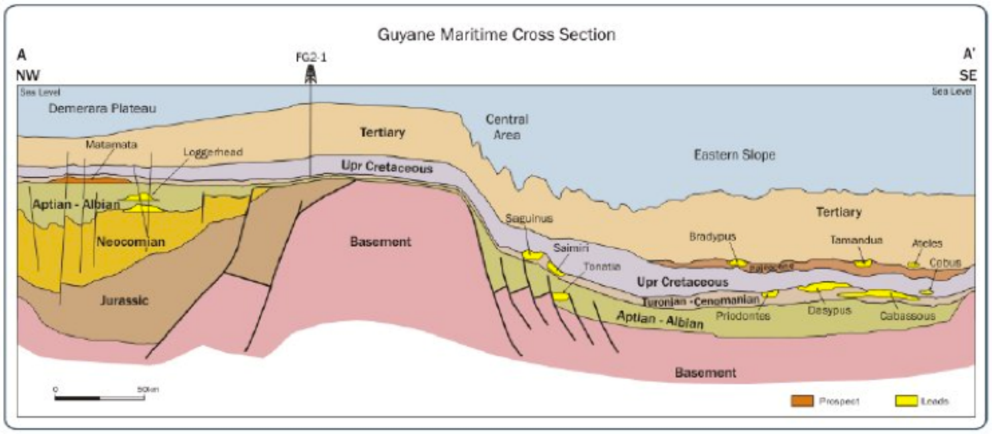
CMS Area EDP

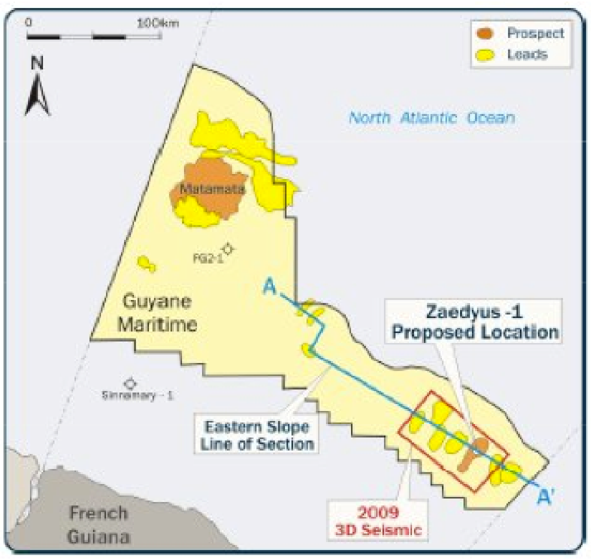


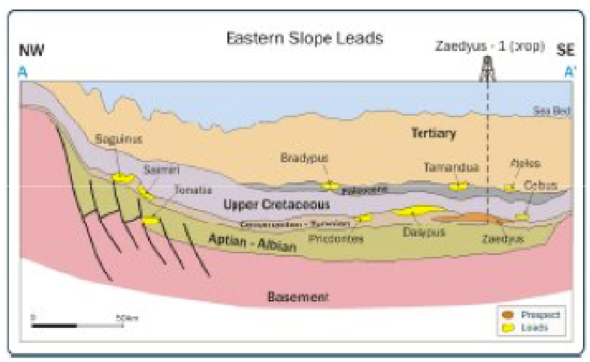
Source: Map Book 2012

Appendix 13 - Guyane Maritime Cross Section

The figure below shows a cross section of the Guyane Maritime area. We see the Saguinus & Samiri channels in the middle of the picture. A large 3D seismic program for these channels is included in the 2012 exploration program.







Appendix 14 - Peer Group

Peer group

As explained in part 2.1.4 there are several factors that makes it difficult to use comparable multiples to value Tullow. To better understand the best comparable companies, the closest peers are presented below. The companies are comparable to Tullow in different fields. The companies described are: Afren PLC, Africa Oil PLC,

Afren PLC

Afren is an independent exploration and production company founded in 2004 by Ethelbert Cooper. Afren is a portfolio player operating in Africa, with 29 licences allocated in 12 countries. Its portfolio constitutes of the full-cycle E&P value chain of exploration, appraisal, development and production. The company is chosen as a peer because operate in many of the same countries as Tullow, such as Ivory Coast, Ghana, Congo, Kenya, Madagascar and Tanzania.

During 2011, they significantly increased both production and their resource base, due to three main events: first oil in Ebok field in Nigeria, the acquisition of a major portfolio onshore Nigeria, and the acquisition of interests in Kurdistan region of Iraq, which increased 3P by over 633%.

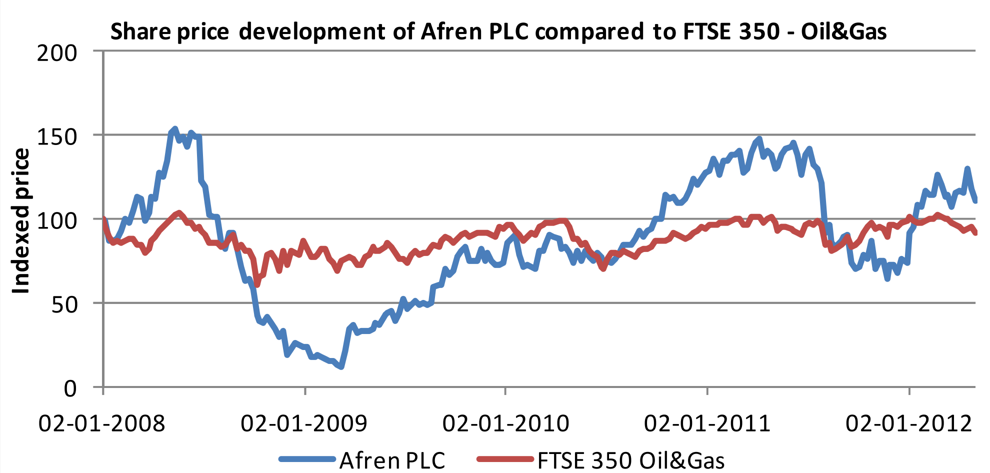
Afren Oil PLC - Key Statistics

Key figures (WI Basis)	2009A	2010A	2011A
Net WI production (boepd)	22.100	14.333	19.154
2P reserves (mmboe)	85,8	79,8	185
3P reserves (mmboe)	112,7	135,7	995,1
Key Financials $ millions	**2009A**	**2010A**	**2011A**
Revenue	335,8	319,4	596,7
Oprating costs ($/boe)	11,6	18,1	17,9
Operating Profit	45,8	89	268,2
Operating Profit margin	13,64%	27,86%	44,95%
EV/EBIT	67	33,9	10,9
EV/EBITDA	15,2	16,5	6,9
P/Book	3	2,5	2
P/E	27,9	31,5	17,9

Source: Afren Annual Report 2011

Major owners include Vidacos Nominees (8,7%), AllianceBernstein LP (8,2%) and Invested Asset Management Ltd (4,4%). The company has one class of ordinary shares with 1 vote per share, and which carries no right to fixed income. The shares have been listed on London stock exchange since March 14th 2005.

Afren Oil PLC - Share price development



Source: Own work based on: Bloomberg

Africa Oil PLC

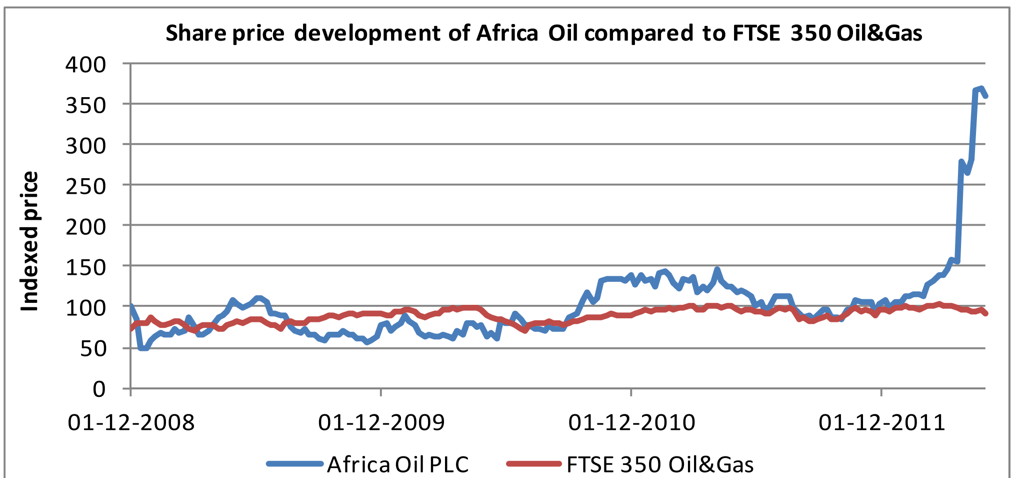
Africa Oil is a Canadian oil and gas company founded as Canmex Minerals Corporation in 1983, and changed name to Africa Oil Corp in August 2007. They are a portfolio player and are involved in exploration in Kenya, Ethiopia and Mali, as well as Puntland in Somalia. Africa Oil is chosen as a peer as it is partner with Tullow both in Kenya (5 blocks[1]) and Ethiopia (South Omo basin). The company has only activities in the exploration stage, and has no producing assets. Hence, there has not been generated any oil or gas revenue to date.

Africa Oil PLC - Key Statistics

Key ratios	2009A	2010A	2011A
Market Cap ($ millions)	81,1	170,3	299,6
P/Book	5,7	6,7	4,8

The shares are listed on the Canadian Stock Exchange (TSX Venture Exchange) and on the NASDAQ OMX First North Exchange in Sweden. The company is part of the Lundin Group, which is a group of companies comprised of individual, publicly traded natural resource companies managed by the Swedish Lundin Family.

Africa Oil PLC - Share price development



Source: Own work based on: Bloomberg

As seen in the figure, Africa Oil's share price more than tripled from January to Mai 2012. The reason for this is the Ngamia-1 oil discovery in Kenya, where they have 50% WI, partnered by Tullow.

1 Block 10A, Block 10BA, Block 10BB, Block 12A, Block 12B, Block 13T

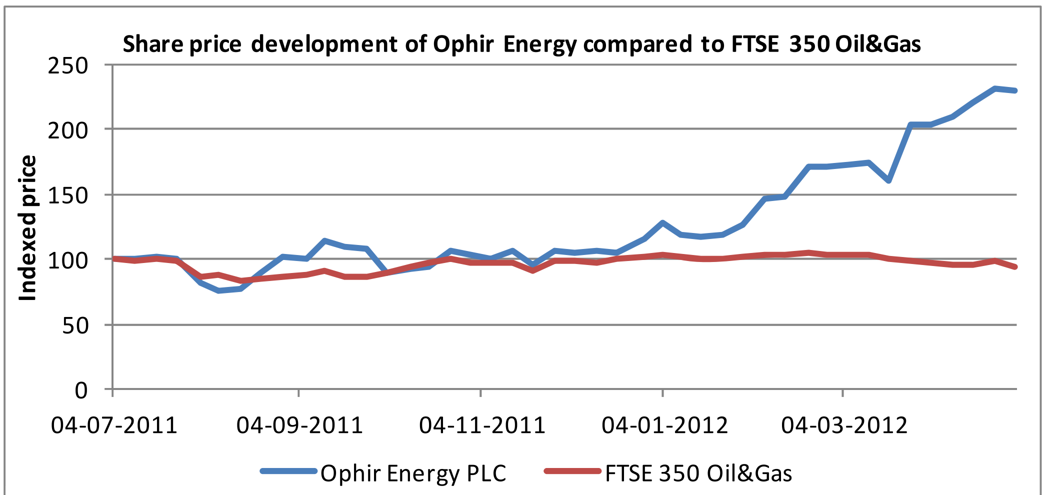
Ophir Energy

Ophir Energy was founded in 2004, and is a UK incorporated oil and gas exploration company. Ophir is a portfolio player and has oil and gas exploration assets in a number of the same African Countries as Tullow, such as Tanzania, Equitorial Guinea, Gabon, Congo, Madagascar, and Kenya. 2011 was dominated by Ophir's IPO, which raised a total of US$384 million, and ended the year as the best performing IPO stock for 2011[2].

The company has no production to date, and hence no oil or gas revenue.

The group issued new shares in 2011, and was listed on the London Stock Exchange on 13th July. Major shareholders include Capital Research global Investors (11.62%), OZ Management LLC (9,09%) and FIL Investments International (5,25%).

Ophir Energy - Share price development



Source: Own work based on: Bloomberg

As seen in the figure the share price has risen steadily since the beginning of the year. This is due to gas findings offshore Tanzania, which significantly exceeded estimates.

2 Ophir Energy: Annual Report 2011

Dragon Oil

Dragon Oil was originally founded as Oliver Prospecting & Mining Company in 1971, and changed its name to Dragon Oil in 1993. It is chosen as a peer because it is a single asset player[3] with its focus on the Cheleken Contract Area offshore Turkmenistan. Being a single asset player, Dragon Oil's share price can give an indication of the market value of fields with similar production profile as Cheleken.

In 2011, average gross production rose 30% to 61.500 bopd, with an exit rate[4] of 71.751 bopd at the end of the year. The company expects an annual production growth of 10-15%, taking field production to a level of over 80.000 bopd in 2012.

Dragon Oil PLC - Key Statistics

Key figures (WI Basis)	2009A	2010A	2011A
Net WI production (boepd)	44.765	47.200	61.500
2P reserves (mmboe)	617	639	658

Key Financials $ millions	2009A	2010A	2011A
Market Cap	309	415	362
Revenue	623	780	1.151
Oprating costs ($/boe)	3,5	3,8	3,3
Operating Profit	314,4	487,7	856,2
Operating Profit margin	50%	63%	74%
EV/EBIT	9,9	6,4	3,6
EV/EBITDA	6,2	4,6	2,9
P/Book	2,9	2,4	1,9
P/E	19,1	12,8	7,6

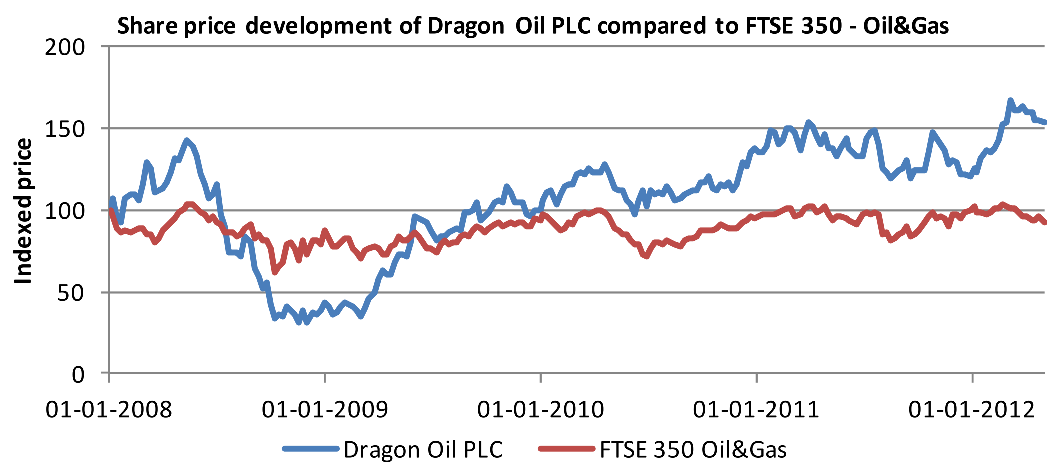
Source: Own work based on: Dragon Oil Annual reports & Bloomberg

The company is registered in Ireland with a primary listing on the Irish Stock Exchange and has, since April 6 2010, been listed on the London Stock Exchange. The government of Dubai owns approximately 51% of the Company's ordinary share capital.

3 One main producing asset, however interests in other small exploration projects.

4 Exit rate: The yearly production if the company were to produce at the daily production volume at the end of the year.

Dragon Oil PLC - Share price development



Source: Own work based on: Bloomberg

Kosmos Energy

Kosmos was founded in 2003 as an organisation focused on finding new oil in underexplored venues. In 2007 the company discovered the massive Jubilee Field offshore Ghana, which today is one of Tullow's main assets. The company is still one of Tullow's partners in the field, and is operator for the West Cape Three Points licence, and a Technical Operator for Phase 1 of the Jubilee Development (Tullow is Unit Operator). Kosmos has also agreed to acquire Sabre's interests in the 3 licences offshore Ghana with completion expected by mid 2012.

Kosmos Energy - Key statistics

Key figures (WI Basis)	2009A	2010A	2011A
Net WI production (boepd)	-	-	16.358
1P reserves (mmboe)	52	56	51

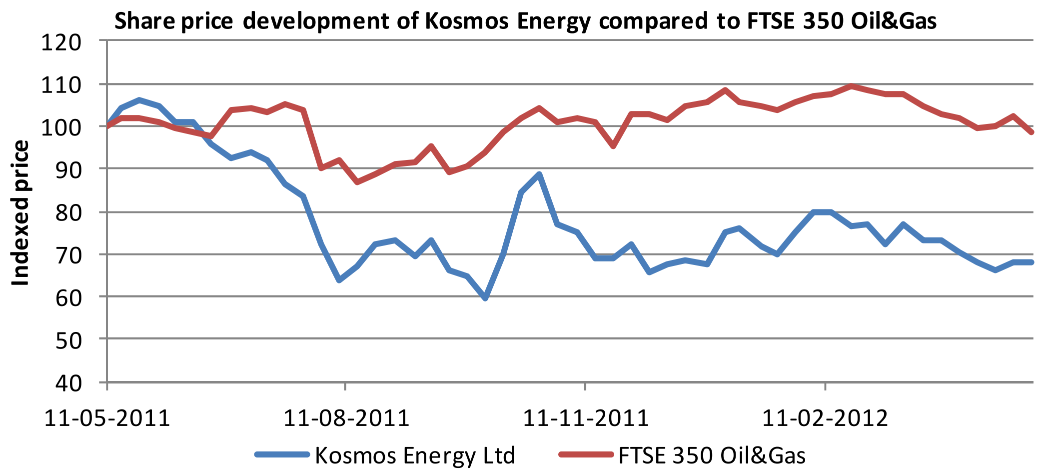
Key Financials $ millions	2009A	2010A	2011A
Revenue	10	9	677
Oprating costs ($/boe)	-	-	13,99
Operating Profit	-79	-323	99
Operating Profit margin	-	-	15%

Source: Own work based on: Kosmos Annual reports & Bloomberg

Kosmos completed its IPO in May 2011, and is now listed on the New York Stock Exchang (NYSE). The two largest shareholders are Warburg Pincus LLC (39,6%) and Blackstone Group

LP (32,4%) and they collectively own approximately 72% of the issued and outstanding common shares[5].

Kosmos Energy - Share price development



Source: Own work based on: Bloomberg

As seen in the figure, Kosmos has clearly underperformed compared to FTSE 350 since its IPO in 2011. The reason for this is unclear, as they have not had any unsuccessful drilling in the time period, or problems in other fields. The most probable cause is thus that the IPO price was set to high, and that this since has been corrected by the market.

5 Morningstar: Kosmos Major Shareholders

Appendix 15 - Accounting Numbers P&L

In the following section the Profit and Loss (P&L), Balance Sheet and Cash Flow Statement will be presented. They are all a function of the overall model, meaning that the values are gathered directly from the modelled fields. In addition a calculation sheet is made which provides different calculations for, among others, financing costs, capex and Plant, Property and Equipment (PP&E).

Table 15.1 Profit and Loss (P&L) 2007 - 2016

P&L		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Revenue (inc. tariff income)	$m	639	692	582,3	1.090	2.304	2.356	2.868	3.126	4.849	6.149
COGS	$m	(151)	(142)	(169,5)	(244)	(397)	(401)	(463)	(568)	(798)	(982)
Admin and other	$m	(32)	(43)	(50)	(90)	(123)	(126)	(130)	(134)	(138)	(142)
EBITDA	$m	457	507	363,3	756	1.784	1.829	2.275	2.424	3.913	5.025
Depreciation, depletion, amortization	$m	(203)	(198)	(228,6)	(367)	(534)	(489)	(629)	(808)	(685)	(892)
E&D w rite off, impairment	$m	(64)	(253)	(52,8)	(155)	(121)	(200)	(220)	(240)	(260)	(280)
EBIT	$m	190	56	81,9	234	1.130	1.140	1.426	1.376	2.968	3.853
Gains / losses	$m	(1)	244	13,2	1	2	1.014	-	-	-	-
Derivatives mark to market	$m	(29)	43	(37,2)	(28)	27	-	-	-	-	-
Net interest	$m	(46)	(43)	(37,6)	(55)	(86)	(42)	(104)	(94)	(110)	(102)
EBT	$m	114	299	20,3	152	1.073	2.112	1.322	1.282	2.858	3.751
Tax	$m	(62)	(73)	(1,8)	(79)	(384)	(925)	(617)	(609)	(1.247)	(1.613)
Net income	$m	53	226	18,5	73	689	1.187	705	673	1.611	2.139
Minorities	$m	(2)	(3)	(3)	(19)	(40)	(41)	(42)	(43)	(44)	(45)
Net earnings attributable	$m	**51**	**223**	**15,1**	**54**	**649**	**1.146**	**663**	**630**	**1.567**	**2.094**
Clean earnings	$m	**51**	**(21)**	**2**	**54**	**647**	**132**	**663**	**630**	**1.567**	**2.094**
Per share data		**2007A**	**2008E**	**2009A**	**2010A**	**2011E**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Year end no. of shares outstanding	m	720	733	800	880	905	905	905	905	905	905
Weighted average basic shares	m	717	732	794	874	903	905	905	905	905	905
Weighted average diluted shares	m	731	732	795	874	902	905	905	905	905	905
Basic EPS	p/sh	7,10	30,50	1,9	4,1	44,7	9,0	45,3	43,2	108,1	144,9
Diluted EPS	p/sh	6,96	30,49	1,9	4,1	44,7	9,0	45,2	43,2	108,0	144,8
Cash EPS	p/sh	47,8	53,3	40,5	46,6	90,9	47,2	84,4	90,8	128,9	226,1
DPS	p/sh	6,0	6,0	6,0	6,0	12,0	14,0	14,0	14,0	14,0	14,0
US$ per share data		**2007A**	**2008A**	**2009A**	**2010A**	**2011E**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Basic EPS	c/sh	7,1	30,5	1,9	6,2	71,7	14,6	73,3	69,7	173,1	231,3
Diluted EPS	c/sh	7,0	30,5	1,9	6,2	71,7	14,6	73,2	69,6	173,1	231,3
Cash EPS	c/sh	47,8	53,3	40,8	71,1	145,7	95,2	171,6	190,2	282,3	365,7

Source: Ow n Calculations, NAV model

Revenues: As seen in the P&L above total revenues have increased from $ 639m in 2007 to estimated $ 6.439m in 2016. This equals an increase of 850%, or a Compound Annual Growth Rate (CAGR) of 28,6%.

Cost of Goods Sold (COGS): COGS is a function of the WI production and the achieved weighted average opex. In other words, all the assumptions done in projecting the different fields, as differences in opex between countries, are included in the accounting numbers.

Admin and other: Calculated as last year´s value with a yearly growth rate of 3%.

Depreciation, depletion and amortization (DD&A): Calculated with an average depreciation amount per barrel multiplied with WI production per year. This average value is guided to $17,3/bbl.

E&D write off, impairment: This value is calculated as a percentage value of 20% out of the respective year´s exploration capex. In other words, it is assumed that 80% of the exploration activity will provide value to Tullow.

Gains/losses: This post is for gains and losses associated with M&A activity. Both the farm-down in Uganda and the sale of the Asian assets are included in 2012, providing a gain of just over $1bn.

Net interest: Net interest is a function of interest charge on their credit facility, provision charge and interest earned on surplus tax. Cost of debt is guided by Tullow to be 4,3%[6] which is the weighted average effective interest rate. This rate is assumed to be unchanged in the future, and is applied to the amount of credit facility used for the respective years. Interest earned is set to 1%[7] for 2012 and forward.

Tax: The efficient tax rate is guided to be between 37 – 42%. In the model an estimate of 40% is used which is calculated from Profit Before Tax (PBT) before exploration costs, which are not deductable.

Minorities: Calculated by previous year´s amount with a yearly growth rate of 2,5%.

Net earnings attributable and Clean earnings: First mentioned include the gains and losses from the year, and Clean Earnings exclude these posts, only looking at the operations.

6 The borrowing rate is determined by US dollar LIBOR and sterling LIBOR with relevant added margin

7 The deposit rate is determined by US dollar LIBOR and sterling LIBOR with relevant added margin

Appendix 16 - Accounting Numbers Balance Sheet

E&P companies are usually funded through equity or, for mature companies, convertible bonds. This is because E&P companies don't have any cash flow, or they may have a negative cash flow. If they were to be financed through debt, this could enforce unnecessary financial stress, and possibly weaken their operational optimization. Credit facilities are therefore commonly used to handle the everyday liquidity control, as Tullow have. They have one Reserve Based Lending Facility of $3,5bn and one Revolving Corporate Facility[8] of $650m, totalling $4,15bn in credit facilities[9].

Due to these facts, the balance sheet is presented with shareholders equity as the final balance, rather than total assets/liabilities, which also is industry standard for E&P companies.

Table 16.1 Balance Sheet 2007 - 2016

Balance sheet ($m)		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
PP&E	$m	832	986	2.174	2.974	3.658	2.197	2.571	3.038	3.336	3.150
Intangibles - exploration & evaluation	$m	957	1.418	2.100	4.001	5.450	6.250	7.130	8.090	9.130	10.250
Investments	$m	0,4	0,4	0,7	1,0	314,5	314,5	314,5	314,5	314,5	314,5
Long term assets	$m	1.789	2.405	4.274	6.977	9.423	8.762	10.016	11.442	12.780	13.714
Inventories, receivables and other	$m	146	167	313	952	858	-	-	-	-	-
Payables	$m	(217)	(435)	(396)	(1.362)	(1.119)	-	-	-	-	-
Non cash working capital	$m	(71)	(268)	(84)	(410)	(260)	(260)	(260)	(260)	(260)	(260)
Other liabilities	$m	(9)	(6)	(20)	-	(2)	(2)	(2)	(2)	(2)	(2)
Provisions	$m	(134)	(134)	(140)	(279)	(441)	(463)	(486)	(510)	(536)	(563)
Deferred tax	$m	(308)	(348)	(266)	(475)	(1.138)	(1.476)	(1.657)	(1.823)	(2.284)	(2.905)
Other liabilities	$m	(450)	(488)	(426)	(754)	(1.581)	(1.941)	(2.145)	(2.336)	(2.822)	(3.470)
Cash	$m	82	311	158	338	307	-	-	-	556	2.207
Debt	$m	(540)	(691)	(817)	(2.200)	(3.076)	(766)	(1.316)	(2.083)	(2.083)	(2.083)
Finance leases	$m	(9)	(9)	(9)	-	-	-	-	-	-	-
Net debt	$m	(467)	(389)	(667)	(1.862)	(2.769)	(766)	(1.316)	(2.083)	(1.527)	124
Net assets for sale	$m	69	-	-	-	-	-	-	-	-	-
Net derivatives	$m	(158)	49,3	(11)	(82)	(47)	(47)	(47)	(47)	(47)	(47)
Net assets	$m	**713**	**1.309**	**3.086**	**3.869**	**4.766**	**5.748**	**6.248**	**6.717**	**8.125**	**10.061**
Minority interest	$m	(15)	(25)	(42)	(61)	(76)	(117)	(159)	(202)	(246)	(291)
Net assets atrributable	$m	**697**	**1.284**	**3.045**	**3.808**	**4.690**	**5.631**	**6.089**	**6.515**	**7.879**	**9.770**
Shareholders equity	$m	697	1.284	3.045	3.808	4.690	5.631	6.089	6.515	7.879	9.770

Source: Own Calculations, NAV model

8 Reserve Based Lending Facility is for larger capital spending as acquisitions and similar investments and Revolving Corporate Facility is for every day liquidity control.

9 Tullow Oil: Annual Report 2011 – *p.38*

Plant, Property and Equipment (PP&E): This post includes development costs capitalized as PP&E, with depreciation in line with DD&A policy.

Intangibles - exploration & evaluation: All license acquisition-, exploration- and appraisal costs (including seismic, drilling and testing) are capitalized within well/field cost centres. Expenditure is then written off if no commercial reserves are declared. This is reclassified to PP&E as producing assets if commercial reserves are established.

Investments: This is the registered lawsuit against Heritage Oil of $313,5m due to the tax dispute regarding the acquisition in 2010 and this amount is carried forward until a verdict is known. The hearing is scheduled to January 2013, and the amount is paid to the Ugandan Revenue Authority[10].

Non Cash Working Capital: This is assumed constant from 2011 levels.

Provisions: This is the capitalized costs associated with the decommission obligations Tullow have when the different fields close down. The amount increases with 5% per year, as decommission date approaches.

Deferred tax: This is calculated along with the overall taxation calculation shown in Appendix 18 - Corporate Tax Calculations. The deferred tax share is based on historical levels.

Cash: After the farm-down of Uganda, Tullow hold a net cash position, but during 2012 capital spending is larger than net cash flow, indicating usage of their credit facility and resulting in net debt ultimo 2012. In the NAV model net cash is used.

Debt: The value is gathered from the cash flow statement, as closing debt. This debt is the credit facility that is used in case of negative cash flow, and is therefore an automatic function based on the respective year´s cash flow.

Net derivatives: Is held constant from 2011 levels.

Net assets attributable: This is the balancing level after subtracting minority interests. A control is made where Net Assets Attributable should match Shareholders equity; where last mentioned is a function of last year´s shareholders equity, net earnings attributable and dividends.

10 Tullow Oil: Annual Report 2011 – *p.138*

Appendix 17 - Accounting Numbers Cash Flow Statement

Table 17.1 Cash Flow Statement

Cashflow statement ($m)		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
EBITDA	$m	457	507	363	756	1.784	1.829	2.275	2.424	3.913	5.025
Working capital changes	$m	(27)	69	(80)	56	71	-	-	-	-	-
Other	$m	17	12	10	6	48	-	-	-	-	-
Operating cashflow	$m	447	588	294	818	1.903	1.829	2.275	2.424	3.913	5.025
Net interest paid	$m	(38)	(37)	(31)	5	14	(20)	(81)	(70)	(85)	(75)
Tax paid	$m	(30)	(77)	(119)	(86)	(172)	(587)	(435)	(443)	(787)	(991)
Cashflow from operations	$m	379	474	144	738	1.745	1.222	1.758	1.912	3.041	3.959
Capex inc. exploration	$m	(364)	(460)	(757)	(798)	(1.654)	(1.933)	(2.102)	(2.475)	(2.283)	(2.105)
Net acquisitions and disposals	$m	(336)	285	11	(1.999)	(402)	3.013	-	-	-	-
Cashflow from investing	$m	(700)	(175)	(746)	(2.797)	(2.055)	1.080	(2.102)	(2.475)	(2.283)	(2.105)
Dividends paid	$m	(39)	(43)	(48)	(79)	(114)	(206)	(205)	(204)	(203)	(202)
Equity raised inc. subsidiary share capital	$m	4	8	397	1.453	87	-	-	-	-	-
Shares purchased	$m	(4)	(11)	(4)	-	-	-	-	-	-	-
Cashflow from financing- ex borrowings	$m	(39)	(46)	346	1.374	(28)	(206)	(205)	(204)	(203)	(202)
Debt raised / (debt repaid)	$m	342	(65)	144	775	331	(3.013)	-	-	-	-
Cashflow from borrowings	$m	342	(65)	144	775	331	(3.013)	-	-	-	-
Other	$m	0	41	(40)	(4)	(25)	-	-	-	-	-
Opening cash	$m	99	82	311	158	244	213	-	-	-	556
Cashflow during year	$m	(17)	229	(153)	86	(31)	(917)	(549)	(767)	556	1.651
Closing cash / (net debt raised)	$m	**82**	**311**	**158**	**244**	**213**	**(703)**	**(549)**	**(767)**	**556**	**2.207**
Closing debt	$m	(540)	(691)	(817)	(2.200)	(3.076)	(766)	(1.316)	(2.083)	(2.083)	(2.083)
Closing (net debt) / net cash	$m	**(467)**	**(389)**	**(667)**	**(1.862)**	**(2.769)**	**(766)**	**(1.316)**	**(2.083)**	**(1.527)**	**124**

Source: Own Calculations, NAV model

DACF / CE / FCF to equity		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2015E
DACF - CF basis	$m	417	511	175	732	1.731	1.242	1.839	1.982	3.126	4.034
DACF - P&L basis	$m	395	433	362	677	1.401	904	1.658	1.815	2.666	3.412
Cash earnings - CF basis	$m	406	405	224	682	1.674	1.222	1.758	1.912	3.041	3.959
Cash earnings - P&L basis	$m	350	390	324	622	1.314	862	1.554	1.721	2.555	3.310
FCF to equity generated	$m	15	13	(613)	(60)	91	(711)	(344)	(563)	759	1.854

Working Capital changes: Assumed to be zero due to assumptions of constant working capital in the forecasting period.

Net Interest Paid: Calculated by subtracting Provision Charge from Net Interest in P&L, because Provision Charge is only an accounting number for decommission obligations of the oil fields in the future.

Tax Paid: This is the amount of total payable taxes that are not classified as deferred tax. See Appendix 18 - Corporate Tax Calculations.

Capex included exploration: This is the projected development capex from the different fields, in addition to the unspecified exploration capex.

Net acquisitions and disposals: The cash inflow from the Ugandan farm-down and an estimated sale of the Asian assets are included.

Cashflow from financing- ex borrowings: This includes dividends paid during the projected time frame. The amount in GBp is constant, but due to an increasing GBP/USD followed by the forward contracts, the dollar value of the dividends decreases.

Debt raised/(debt repaid): Includes down payment of their credit facility after the Ugandan farm-down, and the projected asset sale in Asia.

Closing cash/(net debt raised): This is a function of the cash flow during the year. If one year provides surplus cash, this is assumed to be used as down payment on the credit facility, if there is any. Otherwise it is registered as net cash. Turned around, if the year provides negative cash flow, this is assumed to be covered through their credit facility.

Debt Adjusted Cash Flow (DACF): This is an after tax operating cash flow measurement, excluding financial expenses after taxes. It is good to use in the oil industry, due to high resource taxes, and a good measurement when comparing with other companies.

Appendix 18 - Corporate Tax Calculations

Tax		2007A	2008A	2009A	2010A	2011E	2012E	2013E	2014E	2015E	2016E
PBT	$m	114	299	20	152	1.073	2.112	1.322	1.282	2.858	3.751
PBT pre exploration costs	$m	178	552	73	307	1.194	2.312	1.542	1.522	3.118	4.031
Tax	$m	(62)	(73)	(2)	(79)	(384)	(925)	(617)	(609)	(1.247)	(1.613)
Effective tax rate		-54%	-24%	-9%	-52%	-36%	-44%	-47%	-47%	-44%	-43%
Adjusted tax rate (add back exploration costs)		-35%	-13%	-2%	-26%	-32%	-40%	-40%	-40%	-40%	-40%
Current tax	$m	(41)	(29)	(2)	(134)	(186)	(587)	(435)	(443)	(787)	(991)
Current tax rate	%	-36%	-10%	-9%	-81%	-17%	-25%	-28%	-29%	-25%	-25%
Deferred tax	$m	(20)	(44)	-	44	(198)	(338)	(181)	(166)	(461)	(622)
Deferred tax rate	%	-18%	-15%	0%	29%	-18%	-18%	-18%	-18%	-18%	-18%
Cash tax proportion of current tax	%				64%	92%	100%	100%	100%	100%	100%
Average											
Current tax pasted as values to avoid circular refer	$m						(587)	(435)	(443)	(787)	(991)
Check							(0,0000)	(0,0000)	(0,0001)	(0,0002)	(0,0003)

Appendix 19 - Cash Flow Drivers

CF drivers

Financing		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Closing debt (ex finance costs)	$m	540	691	817	2.200	3.076	3.076	1.235	2.013	2.083	2.083
Average existing debt	$m	374	616	754	1.508	2.638	3.076	2.155	1.624	2.048	2.083
Interest charge before provisions	$m	40	39	45	45	113	33	93	70	88	90
Cost of debt		11%	6%	6%	3%	4%	4,30%	4,30%	4,30%	4,30%	4,30%
Provision charge	$m	9	9	9	9	14	22	23	24	26	27
Provision discount rate		-6,7%	-6,5%	-6,5%	-6,5%	-5,0%	-5,0%	-5,0%	-5,0%	-5,0%	-5,0%
Closing cash (ex finance costs)	$m	82	311	158	338	307	2.329	-	-	641	2.282
Average cash	$m	91	197	235	248	323	1.318	1.165	-	320	1.462
Revenue received	$m	3	4	5	5	10	13	12	-	3	15
Return on cash		3%	2%	2,0%	2,0%	3,0%	1,0%	1,0%	1,0%	1,0%	1,0%
Net interest charge	$m	46	43	49	49	118	42	104	94	110	102
check	$m	(46)	(43)	(38)	(55)	(86)	(42)	(104)	(94)	(110)	(102)

Capex		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Europe	$m		(116)	(70)	(57)	(106)	(123)	(45)	(38)	(38)	(38)
Africa	$m		(253)	(421)	(483)	(559)	(818)	(965)	(1.237)	(945)	(705)
South Asia	$m		-	-	-	-	-	-	-	-	-
Development capex - existing fields	$m		(369)	(491)	(540)	(665)	(941)	(1.010)	(1.275)	(983)	(743)
Development capex (check)	$m		(369)	(491)	(546)	(711)	(933)	(1.002)	(1.275)	(983)	(705)
Development capex	$m	(177)	(469)	(707)	(637)	(396)	(933)	(1.002)	(1.275)	(983)	(705)
Exploration capex	$m	(375)	(489)	(378)	(598)	(1.036)	(1.000)	(1.100)	(1.200)	(1.300)	(1.400)
Total capex	$m	(552)	(959)	(1.085)	(1.235)	(1.432)	(1.933)	(2.102)	(2.475)	(2.283)	(2.105)
% change		66%	74%	13%	14%	16%	35%	9%	18%	-8%	-8%

Source: Own calculations, NAV model, Company Data

Appendix 20 - Balance Sheet Drivers

BS / DRIVERS											
PP&E, intangibles & investments		**2007A**	**2008A**	**2009A**	**2010A**	**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Starting book value- PPE	$m	934	1.639	986	2.174	2.974	3.658	2.197	2.571	3.038	3.336
Capex added	$m	212			637	396	933	1.002	1.275	983	705
Acquisitions net of disposals	$m	(98)			2.006		(1.905)	-	-	-	-
Depreciation charge	$m	(206)			(366)	(493)	(489)	(629)	(808)	(685)	(892)
Impairment / w rite offs / other	$m	(11)	-	-	-	-	-	-	-	-	-
Closing book value- PPE	$m	1.639	986	2.174	2.974	3.658	2.197	2.571	3.038	3.336	3.150
Depreciation rate	%	-21%	0%	0%	-10%	-16%	-15%	-23%	-25%	-19%	-24%
Depreciation /bbl w orking interest basis	$/bbl				(17,3)	(17,3)	(17,3)	(17,3)	(17,3)	(10,0)	(10,0)
Depreciation reported /bbl w orking intere	$/bbl	(15,0)	(15,0)	(16,9)	(17,3)						
Opening Exploartion & Evaluation assets	$m	820	820	1.418	2.100	4.001	5.450	6.250	7.130	8.090	9.130
Additions	$m						1.000	1.100	1.200	1.300	1.400
Transfers net of disposals	$m		-	-			-	-	-	-	-
Impairment & other	$m						(200)	(220)	(240)	(260)	(280)
Closing E&E	$m	820	1.418	2.100	4.001	5.450	6.250	7.130	8.090	9.130	10.250

Minorities		**2007A**	**2008A**	**2009A**	**2010A**	**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**
Opening	$m	14	15	25	42	61	76	117	159	202	246
Additions	$m	2	10	16	19	15	41	42	43	44	45
Closing	$m	15	25	42	61	76	117	159	202	246	291

Appendix 21 - Field Model Numbers

The table below shows the field model CF, gathered from all the projected fields.

Cash generation net of use		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
FIELD MODEL											
Cash carried forward	£m	99	82	129	-	-	-	-	-	-	115
FCF generation from producing fields	$m	339	536	(69)	(304)	606	543	1.214	1.153	1.077	1.087
FCF generation from development fields	$m	-	0	0	0	0	(138)	(711)	(846)	338	1.193
Exploration capex	$m	(375)	(489)	(378)	(598)	(1.036)	(1.000)	(1.100)	(1.200)	(1.300)	(1.400)
Assuming debt repayments are refinanced	$m										
Cash / (net debt required) at end of year	$m	63	129	(318)	(902)	(430)	(595)	(596)	(893)	115	996
CF STATEMENT											
Cash carried over		99	82	338	-	-	-	2.096	1.547	780	1.336
FCF generation net of capex		80	(18)	(503)	(122)	7	(691)	(263)	(493)	844	1.929
Other/ working capital/ net interest		(65)	32	(110)	61	84	(20)	(81)	(70)	(85)	(75)
Dividend payment		(39)	(43)	(48)	(79)	(114)	(206)	(205)	(204)	(203)	(202)
Acquisitions / disposals		(336)	285	11	(1.999)	(402)	3.013	-	-	-	-
Debt repaid- assumed to be refinanced											
Cash remaining / (net debt raised)		(261)	338	(312)	(2.139)	(424)	2.096	1.547	780	1.336	2.987
Field model vs. CF satement model		323	(209)	(6)	1.237	(6)	(2.692)	(2.143)	(1.672)	(1.221)	(1.991)
Field model vs. CF satement model		-124%	-62%	2%	-58%	1%	-128%	-139%	-214%	-91%	-67%

FCF breakdown (Field model)		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Revenue	$m	1.002	1.396	669	849	2.138	2.356	2.868	3.126	4.849	6.149
% change	*%*	*NA*	*39%*	*-52%*	*27%*	*152%*	*10%*	*22%*	*9%*	*55%*	*27%*
Opex	$m	(274)	(233)	(245)	(246)	(351)	(401)	(463)	(568)	(798)	(982)
Pre tax FCF	$m	728	1.163	424	603	1.787	1.955	2.405	2.559	4.051	5.167
Tax	$m	(76)	(257)	(2)	(361)	(470)	(618)	(899)	(976)	(1.654)	(2.181)
Capex	$m	(314)	(369)	(491)	(546)	(711)	(933)	(1.002)	(1.275)	(983)	(705)
FCF generation in year before using cash balances	$m	339	536	(69)	(304)	606	405	504	307	1.415	2.281
Exploration capex	$m	(375)	(489)	(378)	(598)	(1.036)	(1.000)	(1.100)	(1.200)	(1.300)	(1.400)
Net FCF generation in year before cash balances	$m	(37)	47	(447)	(902)	(430)	(595)	(596)	(893)	115	881

Producing		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Revenue	$m	1.002	1.396	669	849	2.138	2.356	2.724	2.546	2.364	2.226
Opex	$m	(274)	(233)	(245)	(246)	(351)	(401)	(434)	(422)	(417)	(412)
Pre tax FCF	$m	728	1.163	424	603	1.787	1.955	2.289	2.125	1.947	1.813
Tax		(73)	(254)	(0)	(357)	(467)	(611)	(863)	(818)	(778)	(695)
Capex	$m	(314)	(369)	(491)	(546)	(711)	(795)	(208)	(149)	(88)	(27)
Other	$m	(3)	(4)	(2)	(3)	(3)	(7)	(5)	(4)	(4)	(4)
FCF generation from PRODUCING fields	$m	339	536	(69)	(304)	606	543	1.214	1.153	1.077	1.087

Development - Uganda, TEN, Jubilee phase 1b		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Revenue	$m	-	0	0	0	0	0	145	580	2.485	3.924
Opex	$m	-	-	-	-	-	-	(29)	(146)	(381)	(570)
Pre tax FCF	$m	-	0	0	0	0	0	115	434	2.104	3.353
Tax	$m	-	-	-	-	-	-	(31)	(154)	(871)	(1.482)
Capex	$m	-	-	-	-	-	(138)	(795)	(1.126)	(895)	(678)
FCF generation from DEVELOPMENT projects	$m	-	0	0	0	0	(138)	(711)	(846)	338	1.193

WI Production	mboe	24,6	23,8	21,3	21,1	28,5	28,3	36,4	46,7	68,5	89,2
opex / bbl	$/boe	(11,1)	(9,8)	(11,5)	(11,6)	(12,3)	(14,2)	(12,7)	(12,2)	(11,7)	(11,0)
opex / bbl	£/boe	(5,6)	(5,3)	(7,3)	(7,7)	(7,7)	(8,7)	(7,9)	(7,5)	(7,3)	(6,9)

Appendix 22 - Analysis Data

	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
RESERVES										
Commercial and Contingent (P50)				1.141						
P50 (developed & undeveloped in mmboe)										
Beginning	506	551	825	894	1388	1139	1139	1139	1139	1139
+ Additions (E&P)				272	235					
+ Acquisitions				303	129					
+/- revisions	114	302	93	11	38					
- Production	-26	-24	-21	-21	-29					
- Disposals	-43	-3	-3	-71	-622					
= P50 YE	551	825	894	1388	1139	1139	1139	1139	1139	1139

ENTERPRISE VALUE (EV)	
Market capitalization	13.906
(+) Core net debt (cash)	-164
(+) Buy out of minorities	
(+) Unfunded pension provisions	
Core enterprise value	**13.742**

Invested Capital	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Non Cash Working Capital	(71)	(268)	(84)	(410)	(260)	(260)	(260)	(260)	(260)	(260)
PP&E	1.789	2.404	4.274	6.976	9.108	8.447	9.701	11.128	12.466	13.400
Other Long term Assets	0	0	1	1	315	315	315	315	315	315
Invested Capital	1.719	2.137	4.191	6.567	9.162	8.502	9.755	11.182	12.520	13.454
EBIT	190	56	82	234	1.130	1.140	1.426	1.376	2.968	3.853
Tax rate	32%	32%	32%	32%	32%	40%	40%	40%	40%	40%
Noplat	129	38	56	159	768	684	855	826	1.781	2.312
ROIC Before Tax	11%	3%	2%	4%	12%	13%	15%	12%	24%	29%
ROIC After Tax	7,5%	1,8%	1,3%	2,4%	8,4%	8,0%	8,8%	7,4%	14,2%	17,2%

Capital Employed	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E
Non Current Assets	1.789	2.405	4.274	6.977	9.423	8.762	10.016	11.442	12.780	13.714
Non Cash Working Capital	(71)	(268)	(84)	(410)	(260)	(260)	(260)	(260)	(260)	(260)
Deffered Income Taxes	*308*	*348*	*266*	*475*	*1.138*	*1.476*	*1.657*	*1.823*	*2.284*	*2.905*
Other Non current liabilities	*134*	*134*	*140*	*279*	*441*	*463*	*486*	*510*	*536*	*563*
Non current liabilities	441	482	406	754	1.579	1.939	2.143	2.333	2.820	3.468
Capital Employed	2.160	2.618	4.597	7.321	10.741	10.440	11.898	13.516	15.340	16.922
ROCE	6,0%	1,4%	1,2%	2,2%	7,2%	6,6%	7,2%	6,1%	11,6%	13,7%
ROACE	6,0%	1,6%	1,5%	2,7%	8,5%	6,5%	7,7%	6,5%	12,3%	14,3%
EBIT Adjusted	189	300	95	235	1132	2154	1426	1376	2968	3853
NOPAT Adjusted	129	204	65	160	770	1292	855	826	1781	2312
ROACE Adjusted	6%	9%	2%	3%	9%	12%	8%	6%	12%	14%

Appendix 23 - Input Assumptions

Oil and gas price scenarios	Units	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2047E	2048E	2049E	2050E	2051E	2052E	2053E	2054E	2055E
Brent price assumption	$/bbl - nominal	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95
gas price assumption	p / therm	35	67	31	42	58	62	67	67	67	65	62	60	57	55	55	55	55	55	55	55	55	55	55
gas price assumption (conversion 0,0972)	$/Mcf	6,8	12,0	4,7	6,2	9,0	9,7	10,5	10,5	10,4	10,0	9,6	9,3	8,9	8,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6

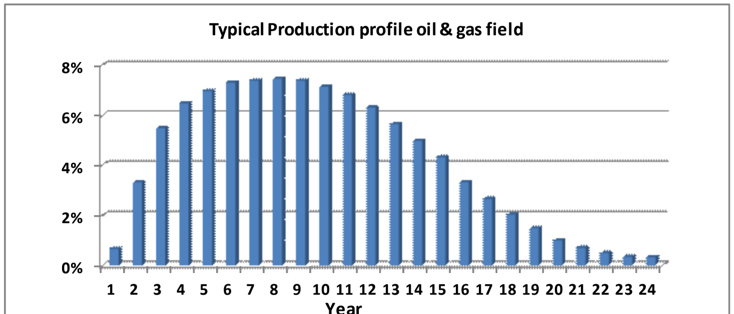
Oil and gas price achieved	Units	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2047E	2048E	2049E	2050E	2051E	2052E	2053E	2054E	2055E
Base Brent price assumption	$/bbl - nominal		93	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Brent oil price achieved for hedging (-10%)	$/bbl - nominal	63	93	63	80	111	106	102	95	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Base gas price assumption	$/bbl	42	74	29	38	56	60	65	65	64	62	60	57	55	53	47	47	47	47	47	47	47	47	47
Base gas price assumption	p / therm	35	67	31	42	58	62	67	67	67	65	62	60	57	55	55	55	55	55	55	55	55	55	55
UK gas price achieved	p / therm	35	67	31	42	58	62	67	67	67	65	62	60	57	55	55	55	55	55	55	55	55	55	55
UK gas price achieved	$/bbl- nominal	42	74	29	38	56	60	65	65	64	62	60	57	55	53	47	47	47	47	47	47	47	47	47
UK gas price achieved	$/ mscf	7	12	5	6	9	10	10	11	10	10	10	9	9	9	8	8	8	8	8	8	8	8	8

Cost Inflation and FX rate	Units	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2047E	2048E	2049E	2050E	2051E	2052E	2053E	2054E	2055E
Fx rate	$/£	1,97	1,84	1,58	1,51	1,60	1,62	1,62	1,61	1,60	1,60	1,60	1,60	1,60	1,60	1,42	1,42	1,42	1,42	1,42	1,42	1,42	1,42	1,42
Underlying cost inflation rate	%							0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Opex costs	Units	2007A	2008A	2009A	2010A	2011A	2012A	2013A	2014A	2015A	2016A	2017A	2018A	2019A	2020A	2047A	2048A	2049A	2050A	2051A	2052A	2053A	2054A	2055A
Gabon	$/boe	12,6	11,8	18,1	19,1	25,4	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0
Ivory Coast, Eq Guinea, Congo (Brazzaville)	$/boe	6,3	5,9	8,5	9,0	10,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0
Mauritania- variable	$/boe	19,3	18,0	25,2	26,6	35,1	55,0	41,3	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6	20,6
South Asia	$/boe	3,0	2,8	2,5	2,7	3,3	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0	4,0
Uganda (Tanzania)- variable	$/boe			9,0	9,9	10,4	11,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0
Ghana- variable	$/boe			7,0	7,7	6,6	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
Namibia- variable	$/boe					10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0	10,0
UK SNS - variable	$/boe					19,4	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0
The Netherlands	$/boe					17,1	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0
Sierra Leone and South America - Varable	$/boe			7,0	7,7	8,1	8,5	8,7	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0
Suriname	$/boe			4,0	4,4	4,6	4,9	5,0	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1
Liberia - variable	$/boe			7,0	6,7	7,0	7,3	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6
Achieved opex cost	**$/boe**	**11,11**	**9,81**	**11,53**	**11,64**	**12,32**	**14,20**	**12,75**	**12,16**	**11,66**	**11,02**	**11,8**	**11,9**	**12,1**	**12,2**	**12,0**	**12,0**	**12,0**	**12,0**	**12,0**	**12,0**	**12,0**	**12,0**	**12,0**

Source: Tullow Oil

Depreciation /bbl working interest basis	$/bbl
OIL:GAS FACTOR	6,0
Commodity inflation rate	0%
Admin and other	3%
Effective tax rate	40%
WACC	8,86%
Conversion factors	
therm to mcf conversion	0,0972
1 bcf = 1/6 mboe	0,17
1 kboe = x mmscf	5,984



Source: Own estimations, NAV Model

COST RECOVERY - ASSUMPTIONS FOR FIELDS as % of Gross Revenue

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22
General	80%	50%	30%	20%	20%	20%	15%	15%	15%	15%	15%	10%	10%	5%	5%	5%	2%	2%	2%	2%	2%	2%

Production Life Cycle - assumptions

Production	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
% out of total amount	1%	3%	5%	6%	7%	7%	7%	7%	7%	7%	7%	6%	6%	5%	4%	3%	3%	2%	1%	1%	1%	0%	0,3%	0,3%
Sum	100%																							

Appendix 24 - DCF Ivory Coast

Country	**Ivory Coast**
Working interest	**21%**
Espoir ex. acajou	

Pricing assumption		2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Oil Price (Brent)	$/bbl	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5
Realised oil price	$/bbl	118	113	105	99	94	95	95	95	95	95	95	95	95	95	95	95	95	95
Reaslised gas price equivalent	$/mcf	20	19	18	17	16	16	16	16	16	16	16	16	16	16	16	16	16	16

Production assumption		2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Oil production	kboe/d	13	17	18	18	18	18	18	13	9	6	4	3	0	0	0	0	0	0
Gas production	mmcf/d	10	20	20	15	10	5	3	0	0	0	0	0	0	0	0	0	0	0
Field production	**kboe/d**	**14**	**20**	**21**	**21**	**20**	**19**	**19**	**13**	**9**	**6**	**4**	**3**	**0**	**0**	**0**	**0**	**0**	**0**
Cumulative production	mboe	89	96	104	112	119	126	132	137	140	143	144	145	145	145	145	145	145	145
Net Tullow		**3**	**4**	**5**	**4**	**4**	**4**	**4**	**3**	**2**	**1**	**1**	**1**	**0**	**0**	**0**	**0**	**0**	**0**

Example of Net Cash flow calculation

Revenue calculation			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Gas revenue			72	137	128	90	57	29	17	0	0	0	0	0	0	0	0	0	0	0
Oil revenue			559	699	692	651	619	621	621	435	304	213	149	104	0	0	0	0	0	0
Gross Revenue		$m	**630**	**836**	**821**	**741**	**676**	**650**	**638**	**435**	**304**	**213**	**149**	**104**	**0**	**0**	**0**	**0**	**0**	**0**
Recoverd Costs inc Capex		$m	-95	-84	-82	-37	-34	-32	-13	-9	-6	-4	-3	-2	0	0	0	0	0	0
Profit Oil available		$m	536	752	739	704	642	617	625	426	298	209	146	102	0	0	0	0	0	0
Contractors Share - A function of PSC		%	47%	42%	42%	42%	47%	47%	47%	47%	49%	49%	49%	49%	49%	49%	49%	49%	49%	49%
Contractors Share		$m	252	316	310	296	302	290	294	200	145	101	71	50	0	0	0	0	0	0
Working interest			21%	21%	21%	21%	21%													
Tullows share			**54**	**67**	**66**	**63**	**64**	**62**	**63**	**43**	**31**	**22**	**15**	**11**	**0**	**0**	**0**	**0**	**0**	**0**
Contractor take of cashflows			**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**
Contractor revenues including cost recovery		$m	346	400	392	333	336	323	307	209	151	105	74	52	0	0	0	0	0	0
Actual costs inc. Capex		$m	-262	-181	-175	-175	-145	-135	-85	-60	-42	-29	-21	-114	0	0	0	0	0	0
Domestic Supply Obligation- payments	12,00%	$m	-31	-22	-21	-21	-17	-16	-10	-7	-5	-4	-2	-14	0	0	0	0	0	0
Net contractor cashflow		$m	**53**	**197**	**196**	**136**	**173**	**171**	**211**	**142**	**104**	**73**	**51**	**-76**	**0**	**0**	**0**	**0**	**0**	**0**
Net Tullow cashflow		$m	**11**	**42**	**42**	**29**	**37**	**36**	**45**	**30**	**22**	**15**	**11**	**-16**	**0**	**0**	**0**	**0**	**0**	**0**

Source: Own calculations, NAV model and Tullow Oil

Actual Costs			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Variable production costs/bbl		$/bbl	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0
Production costs		$m	62	81	85	85	85	85	85	60	42	29	21	14	0	0	0	0	0	0
Capex	851	$m	200	100	90	90	60	50	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs	100	$m											0	100						
Total costs		**$m**	**262**	**181**	**175**	**175**	**145**	**135**	**85**	**60**	**42**	**29**	**21**	**114**	**0**	**0**	**0**	**0**	**0**	**0**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	1023	$m
Remaining NPV- Tullow	229	$m
EV / 2P remaining WI	18 boe WI	
EV / 2P remaining entitled	$ / boe ent	
Discount rate	8,9%	
Gross remaining reserves	61	

Contractor Share
49%
47%
42%
37%
32%

PSC - Oil Production		Production	Contractor Share
kboe/d	<	10	49%
kboe/d	<	20	47%
kboe/d	<	30	42%
kboe/d	>	30	37%

Source: Company Data Ivory Coast, NAV Model

Tullow Equity	21%	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Net Production	**kboe/d**	3	4	5	4	4	4	4	3	2	1	1	1	0	0	0	0	0	0
Net revenues	$m	74	85	84	71	72	69	65	45	32	22	16	11	0	0	0	0	0	0
Net opex	$m	-13	-17	-18	-18	-18	-18	-18	-13	-9	-6	-4	-3	0	0	0	0	0	0
Net capex	$m	-43	-21	-19	-19	-13	-11	0	0	0	0	0	0	0	0	0	0	0	0
Other costs	$m	-7	-5	-4	-4	-4	-3	-2	-2	-1	-1	-1	-3	0	0	0	0	0	0
Net cash	$m	11	42	42	29	37	36	45	30	22	15	11	5	0	0	0	0	0	0

Appendix 25 - DCF Ivory Coast 2015 -

Country	Ivory Coast 2015 -
Working interest	100%

Pricing assumption			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Oil Price (Brent)	$/bbl		111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Production assumption			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Production profile- % of initial reserves mboe (%)	1000		0%	0%	0%	0%	3,0%	12,2%	9,0%	8,0%	5,0%	4,9%	4,8%	4,5%	4,3%	4,0%	3,9%	3,8%	3,7%	3,6%	3,5%	3,4%	3,3%	3,2%	3,1%	3,0%	2,9%	1,0%	1,0%	0,9%
Oil production	kboe/d		0	0	0	0	82	334	247	219	137	134	132	123	118	110	107	104	101	99	96	93	90	88	85	82	79	27	27	25
Cumulative production	mboe		0	0	0	0	30	152	242	322	372	421	469	514	557	597	636	674	711	747	782	816	849	881	912	942	971	981	991	1000

Revenue calculation			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Gross Revenue		$m	**0**	**0**	**0**	**0**	**2985**	**11531**	**8550**	**7600**	**4750**	**4655**	**4560**	**4275**	**4085**	**3800**	**3705**	**3610**	**3515**	**3420**	**3325**	**3230**	**3135**	**3040**	**2945**	**2850**	**2755**	**950**	**950**	**855**
Recoverd Costs inc Capex		$m	0	0	0	0	-2388	-8649	-2565	-1520	-950	-931	-684	-641	-613	-570	-556	-361	-352	-171	-166	-162	-63	-61	-59	-57	-55	-19	0	0
Profit Oil available		$m	0	0	0	0	597	2883	5985	6080	3800	3724	3876	3634	3472	3230	3149	3249	3164	3249	3159	3069	3072	2979	2886	2793	2700	931	950	855
Contractors Share		%	55%	55%	55%	55%	55%	40%	45%	45%	53%	53%	53%	53%	53%	53%	53%	53%	53%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%	55%
Contractors Share		$m	0	0	0	0	328	1153	2693	2736	2014	1974	2054	1926	1840	1712	1669	1722	1677	1787	1737	1688	1690	1639	1587	1536	1485	512	523	470
Tullows share			**0**	**0**	**0**	**0**	**328**	**1153**	**2693**	**2736**	**2014**	**1974**	**2054**	**1926**	**1840**	**1712**	**1669**	**1722**	**1677**	**1787**	**1737**	**1688**	**1690**	**1639**	**1587**	**1536**	**1485**	**512**	**523**	**470**

Contractor take of cashflows			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Contractor revenues		$m	0	0	0	0	2717	9802	5258	4256	2964	2905	2738	2567	2453	2282	2225	2083	2028	1958	1904	1849	1752	1699	1646	1593	1540	531	523	470
Actual costs inc. Capex		$m	0	0	-3430	-4900	-1860	-1584	-1170	-1040	-650	-637	-624	-585	-559	-520	-507	-494	-481	-468	-455	-442	-429	-416	-403	-390	-377	-130	-130	-117
Domestic Supply Obligation- payments	5,00%	$m	0	0	-172	-245	-93	-79	-59	-52	-33	-32	-31	-29	-28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net contractor cashflow		$m	**0**	**0**	**-3602**	**-5145**	**764**	**8139**	**4030**	**3164**	**2282**	**2236**	**2083**	**1953**	**1866**	**1762**	**1718**	**1589**	**1547**	**1490**	**1449**	**1407**	**1323**	**1283**	**1243**	**1203**	**1163**	**401**	**393**	**353**
Net Tullow cashflow		$m	**0**	**0**	**-3602**	**-5145**	**764**	**8139**	**4030**	**3164**	**2282**	**2236**	**2083**	**1953**	**1866**	**1762**	**1718**	**1589**	**1547**	**1490**	**1449**	**1407**	**1323**	**1283**	**1243**	**1203**	**1163**	**401**	**393**	**353**

Actual Costs			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Variable production costs/bbl		$/bbl	10,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0
Production costs		$m	0	0	0	0	390	1584	1170	1040	650	637	624	585	559	520	507	494	481	468	455	442	429	416	403	390	377	130	130	117
Capex	9800	$m	0	0	3430	4900	1470	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs	0	$m																												
Total costs		**$m**	**0**	**0**	**3430**	**4900**	**1860**	**1584**	**1170**	**1040**	**650**	**637**	**624**	**585**	**559**	**520**	**507**	**494**	**481**	**468**	**455**	**442**	**429**	**416**	**403**	**390**	**377**	**130**	**130**	**117**

Capex & depreciation	Total		2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized capex	9800	$m	0	0	0	2744	6115	6068	4855	3884	3107	2486	1988	1591	1273	1018	814	652	521	417	334	267	214	171	137	109	87	70	56	45
Capex added	9800	$m	**0**	**0**	**3430**	**4900**	**1470**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Depreciation @ 20%	20%	$m	0	0	-686	-1529	-1517	-1214	-971	-777	-621	-497	-398	-318	-255	-204	-163	-130	-104	-83	-67	-53	-43	-34	-27	-22	-17	-14	-11	-9
Closing NBV		$m	0	0	2744	6115	6068	4855	3884	3107	2486	1988	1591	1273	1018	814	652	521	417	334	267	214	171	137	109	87	70	56	45	36
Capex phasing	TLW guidanc	100%		**0%**	**35%**	**50%**	**15%**																							
Capex	10	$/boe																												
Abandonment costs	1,0																													
Capex check																														

VALUATION	PV OF EV FCF	
Remaining NPV - gross	11540	$m
Remaining NPV- Tullow	11540	$m
EV / 2P remaining WI	11,54	$/ boe WI
EV / 2P remaining entitled		$ / boe ent
Discount rate	8,9%	
Gross remaining reserves	1000	

PSC - Oil Production			
		Cumulative prod.	contractor share
kboe/d	<	100	55%
kboe/d	<	200	53%
kboe/d	<	300	45%
kboe/d	>	300	40%

Tullow Equity		100%	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Net Production		**kboe/d**	0	0	0	0	82	334	247	219	137	134	132	123	118	110	107	104	101	99	96	93	90	88	85	82	79	27	27	25
Net revenues		$m	0	0	0	0	2717	9802	5258	4256	2964	2905	2738	2567	2453	2282	2225	2083	2028	1958	1904	1849	1752	1699	1646	1593	1540	531	523	470
Net opex		$m	0	0	0	0	-390	-1584	-1170	-1040	-650	-637	-624	-585	-559	-520	-507	-494	-481	-468	-455	-442	-429	-416	-403	-390	-377	-130	-130	-117
Net capex		$m	0	0	-3430	-4900	-1470	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Costs		$m	0	0	-172	-245	-93	-79	-59	-52	-33	-32	-31	-29	-28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net cash		$m	0	0	-3602	-5145	763,76	8138,78	4029,75	3164	2281,5	2235,87	2083,08	1952,89	1866,09	1761,9	1717,85	1588,97	1547,16	1489,95	1448,56	1407,18	1323,47	1283,36	1243,26	1203,15	1163,05	401,05	392,5	353,25

Appendix 26 - DCF Equatorial Guinea – CEIBA

Equatorial guinea (Ceiba)
Working interest 14%
Gross remaining reserves 64

Production assumption			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Field production	**kboe/d**		**45**	**45**	**43**	**41**	**20**	**24**	**30**	**26**	**20**	**16**	**12**	**9**	**6**	**4**	**3**	**2**	**2**
Cumulative production	mboe		99	116	131	146	154	162	173	183	190	196	200	204	206	207	209	209	210
Net Tullow			6,4	6,3	6,1	5,8	2,85	3,4	4,3	3,7	2,9	2,3	1,7	1,3	0,9	0,6	0,4	0,3	0,3
Initial reservoir	mboe	220																	

Pricing assumption	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Oil Price (Brent)	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95
Discount to Brent	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0
Realised oil price	67,4	91,9	57,6	75,0	105,9	113,2	108,1	100,9	94,5	89,7	90,0	90,0	90,0	90,0	90,0	90,0	90,0

Revenue calculation		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Gross revenue	$m	1107	1493	904	1123	773	988	1185	958	690	524	403	296	197	138	97	68	66
Less royalty	%	12%	12%	12%	12%	11%	11%	12%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%
Royalty	$m	-133	-179	-109	-135	-85	-109	-142	-105	-76	-58	-44	-33	-22	-15	-11	-7	-7
Recoverd Costs inc Capex	$m	-166	-224	-136	-168	-77	-99	-59	-48	-35	-10	-8	-6	-4	-3	-2	0	0
Profit Available	$m	808	1090	660	820	611	780	983	805	580	456	350	257	172	120	84	60	59
Profit share		85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	70%	70%	70%	70%	70%	70%	70%
Total profit for operators		687	926	561	697	519	663	836	684	493	387	245	180	120	84	59	42	41
Contract revenues (included recovered costs inc. Capex)		853	1150	697	865	597	762	895	732	527	398	253	186	124	87	61	42	41
Tullow Share		**122**	**164**	**99**	**123**	**85**	**109**	**128**	**104**	**75**	**57**	**36**	**27**	**18**	**12**	**9**	**6**	**6**

Contractor take of cashflows			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Contractor revenues		$m	853	1150	697	865	597	762	895	732	527	398	253	186	124	87	61	42	41
Actual costs inc. Capex		$m	-194	-146	-219	-134	-133	-263	-232	-213	-175	-136	-98	-43	-28	-20	-14	-10	-59
Income tax	20,00%	$m	-171	-230	-139	-173	-119	-152	-179	-146	-105	-80	-51	-37	-25	-17	-12	1	1
Net contractor cashflow		$m	**489**	**775**	**339**	**558**	**344**	**346**	**484**	**372**	**247**	**182**	**104**	**106**	**71**	**50**	**35**	**33**	**-18**
Net Tullow cashflow		$m	**70**	**110**	**48**	**79**	**49**	**49**	**69**	**53**	**35**	**26**	**15**	**15**	**10**	**7**	**5**	**5**	**-3**

Actual Costs			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Variable production costs/bbl		$/bbl	6,3	5,9	8,5	9,0	10,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0
Production costs		$m	104	96	134	134	73	113	142	123	95	76	58	43	28	20	14	10	9
Capex	795	$m	90	50	85	0	60	150	90	90	80	60	40	0	0	0	0	0	0
Abandonment costs		$m														0			50
Total costs		**$m**	**194**	**146**	**219**	**134**	**133**	**263**	**232**	**213**	**175**	**136**	**98**	**43**	**28**	**20**	**14**	**10**	**59**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	1472	$m
Remaining NPV- Tullow	210	$m
EV / 2P remaining WI	23	$/ boe WI
Discount rate	8,9%	

PSC - Cumulative Oil Production		
Cumulative Production		**Contractor Share**
mboe	200	85%
mboe	350	70%
mboe	450	60%
mboe	550	50%
mboe	> 550	40%

PSC - Royalty rate dependent on daily production		
	Production	**Contractor Share**
kboe/d	30	11%
kboe/d	60	12%
kboe/d	80	14%
kboe/d	100	15%
kboe/d		16%

Source: Company Data Equatorial Guinea, NAV Model

Appendix 27 - DCF Equatorial Guinea – OKUME

Equatorial guinea (Okume Complex)
Working interest 14%

Production assumption			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E
Field production	**kboe/d**		29	34	36	38	72	49	38	37	35	33	29	26	22	17	14	11	8	5	4	3	2	2
Cumulative production	mboe		18	31	44	58	84	102	116	129	142	154	165	174	183	189	194	198	201	203	204	205	205	206
Net Tullow			4	5	5	5	10,2	6,9	5	5	5	5	4	4	3	2	2	2	1	1	1	0	0	0
Initial reservoir	mboe	190																						

Pricing assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E
Oil Price (Brent)	$/bbl	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0	-5,0
Realised oil price	$/bbl	67,4	91,9	57,6	75,0	105,9	113,2	108,1	100,9	94,5	89,7	90,0	90,0	90,0	90,0	90,0	90,0	90,0	90,0	90,0	90,0	90,0	90,0

Revenue calculation		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E
Gross revenue	$m	701	1130	763	1041	2768	2004	1518	1368	1222	1074	965	852	738	568	454	348	255	170	119	83	58	57
Less royalty rate	%	11%	12%	12%	12%	14%	12%	12%	12%	12%	12%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%	11%
Rayalty	$m	-77	-136	-92	-125	-388	-240	-182	-164	-147	-129	-106	-94	-81	-62	-50	-38	-28	-19	-13	-9	-6	6
Recoverd Costs inc Capex	$m	-351	-339	-153	-208	-554	-301	-228	-205	-183	-161	-97	-85	-37	-28	-23	-7	-5	-3	-2	-2	-1	0
Profit Available	$m	274	655	519	708	1827	1463	1108	999	892	784	762	673	620	477	381	303	222	148	104	73	51	63
Profit share	%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	70%	70%	70%	70%	70%	70%
Total profit for operators	$m	232	557	441	602	1553	1243	942	849	758	667	648	572	527	405	324	257	156	104	73	51		
Contract revenues (included recovered costs inc. Capex)	$m	583	896	594	810	2107	1544	1169	1054	942	828	745	657	564	434	347	264	161	107	75	53	1	0
Tullow Share		**83**	**128**	**85**	**115**	**300**	**220**	**167**	**150**	**134**	**118**	**106**	**94**	**80**	**62**	**49**	**38**	**23**	**15**	**11**	**7**	**0**	**0**

Contractor take of cashflows			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E
Contractor revenues		$m	583	896	594	810	2107	1544	1169	1054	942	828	745	657	564	434	347	264	161	107	75	53	1	0
Actual costs inc. Capex		$m	-391	-222	-278	-306	-461	-430	-432	-376	-268	-156	-139	-123	-107	-82	-66	-50	-37	-25	-17	-12	-8	-108
Income tax	20,00%	$m	-117	-179	-119	-162	-421	-309	-234	-211	-188	-166	-149	-131	-113	-87	-69	-53	-32	-21	-15	-11	0	0
Net contractor cashflow		$m	**76**	**494**	**197**	**342**	**1225**	**805**	**503**	**467**	**485**	**507**	**456**	**403**	**344**	**265**	**212**	**161**	**92**	**61**	**43**	**30**	**-8**	**-108**
Net Tullow cashflow		$m	**11**	**70**	**28**	**49**	**175**	**115**	**72**	**67**	**69**	**72**	**65**	**57**	**49**	**38**	**30**	**23**	**13**	**9**	**6**	**4**	**-1**	**-15**
			146																					

Actual Costs			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E
Variable production costs/bbl		$/bbl	6,3	5,9	8,5	9,0	10,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0	13,0
Production costs		$m	66	72	113	124	261	230	182	176	168	156	139	123	107	82	66	50	37	25	17	12	8	8
Capex	1772	$m	325	150	165	182	200	200	250	200	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs		$m																						100
Total costs		**$m**	**391**	**222**	**278**	**306**	**461**	**430**	**432**	**376**	**268**	**156**	**139**	**123**	**107**	**82**	**66**	**50**	**37**	**25**	**17**	**12**	**8**	**108**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	3086	$m
Remaining NPV- Tullow	440	$m
EV / 2P remaining WI	25	$/ boe WI
Discount rate	8,9%	
Gross remaining reserves	122	mboe
Net Tullow	17,4	mboe

Profit oil split dependent on cumulative prod		
	Production	contractor share
mboe	200	85%
mboe	350	70%
mboe	450	60%
mboe	550	50%
mboe	>550	40%

Royalty rate dependent on daily production		
	Production	contractor share
kboe/d	30	11%
kboe/d	60	12%
kboe/d	80	14%
kboe/d	100	15%
kboe/d	>100	16%

Appendix 28 - DCF Gabon – All fields

Gabon All Fields		
Working interest	100%	

NB! WI amounts are given by Tullow, and this is projected based on their guidence and remaining reservoir levels

Production assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Field production	**kboe/d**	15	13	12	13	13	13	13	13	13	13	13	13	13	9	6	4	3	3	0
Cumulative production	mboe	93	98	102	107	111	116	121	126	130	135	140	145	149	153	155	157	158	159	159

Pricing assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Oil Price (Brent)	$/bbl	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	-1,5	-2,0	-3,0	-2,3	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	-2,0	0,0	0,0	0,0	0,0
Realised oil price	$/bbl	71	95	60	78	109	116	111	104	98	93	93	93	93	93	93	95	95	95	95

Revenue calculation		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Gross revenue	$m	380	447	259	366	505	551	527	493	463	440	441	441	441	309	216	155	108	104	0
Less royalty rate	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Royalty		-38	-45	-26	-37	-50	-55	-53	-49	-46	-44	-44	-44	-44	-31	-22	-15	-11	-10	0
Recoverd Costs inc Capex		-190	-134	-52	-73	-151	-133	-129	-124	-119	-116	-94	-44	-22	-15	-11	-3	-2	-2	0
Profit Available		152	268	181	256	303	364	346	320	297	280	303	353	375	263	184	136	95	92	0
Profit share		45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	45%	50%	50%	50%	50%	50%	50%
Total profit for operators		68	121	82	115	137	164	155	144	134	126	136	159	169	131	92	68	48	46	0
Contract revenues (included recovered costs inc. Capex)		259	255	133	189	288	296	285	268	253	242	230	203	191	147	103	71	50	48	0
Tullow Share		**259**	**255**	**133**	**189**	**288**	**296**	**285**	**268**	**253**	**242**	**230**	**203**	**191**	**147**	**103**	**71**	**50**	**48**	**0**

Contractor take of cashflows		2000A	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Contractor revenues	$m		259	255	133	189	288	296	285	268	253	242	230	203	191	147	103	71	50	48	0
Actual costs inc. capex	$m		-98	-70	-94	-95	-128	-304	-204	-154	-109	-109	-109	-109	-104	-73	-51	-36	-25	-24	-50
Net contractor cashflow	$m		**161**	**184**	**40**	**94**	**160**	**-8**	**80**	**113**	**144**	**132**	**121**	**94**	**86**	**74**	**52**	**35**	**25**	**24**	**-50**
Net Tullow cashflow (100%)	$m		**161**	**184**	**40**	**94**	**160**	**-8**	**80**	**113**	**144**	**132**	**121**	**94**	**86**	**74**	**52**	**35**	**25**	**24**	**-50**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	632	$m
Remaining NPV - Tullow	632	$m
EV / 2P remaining WI	12,14	$/ boe WI
Discount rate	8,9%	
Reserves data- on 2P basis		
Gross remaining reserves	52	mboe
Working interest reserves	52	mboe

PSC - Oil Production		
	Production	Contractor Share
kboe/d	10	50%
kboe/d	20	45%
kboe/d	30	40%
kboe/d	40	35%
kboe/d	>40	30%

Source: Company Data Gabon, NAV Model

Actual Costs			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Variable production costs/bbl		$/bbl	12,6	11,8	18,1	19,1	25,4	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0
Production costs		$m	68	55	79	90	118	104	104	104	104	104	104	104	104	73	51	36	25	24	0
Capex Including Exploration	699	$m	30	15	15	5	10	200	100	50	5	5	5	5	0	0	0	0	0	0	0
Exploration		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs														0							50
Total costs		**$m**	**98**	**70**	**94**	**95**	**128**	**304**	**204**	**154**	**109**	**109**	**109**	**109**	**104**	**73**	**51**	**36**	**25**	**24**	**50**

Appendix 29 - DCF Congo – M´Boundi

Congo M'Boundi
Working interest 11%

Production assumption			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Field production	**kboe/d**		**14**	**24**	**28**	**30**	**27**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**9**	**7**	**4**	**3**
Cumulative production	mboe		7	16	26	37	47	55	63	71	79	87	95	103	111	119	127	135	138	141	142	143
Total reserves	159	mboe																				

Pricing assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Oil Price (Brent)	$/bbl	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	72	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95

Revenue calculation			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Gross revenue	$m		382	844	644	887	1104	941	901	843	793	754	757	757	757	757	757	757	307	226	150	105
Less royalty rate	12%		12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Rayalty			-46	-101	-77	-106	-133	-113	-108	-101	-95	-90	-91	-91	-91	-91	-91	-91	-37	-27	-18	-13
Recoverd Costs inc Capex			-115	-169	-129	-177	-166	-141	-135	-126	-119	-75	-76	-38	-38	-15	-15	-15	-6	-5	-3	0
Profit Available			222	574	438	603	806	687	658	616	579	588	590	628	628	651	651	651	264	194	129	93
Profit share	0%		50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Total profit for operators			111	287	219	302	403	344	329	308	289	294	295	314	314	325	325	325	132	97	65	46
Tullow Share		**0**	**12**	**32**	**24**	**33**	**44**	**38**	**36**	**34**	**32**	**32**	**32**	**35**	**35**	**36**	**36**	**36**	**15**	**11**	**7**	**5**

Contractor take of cashflows		2000A	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Contractor revenues (after royalties)	$m		225	456	348	479	569	485	464	434	408	369	371	352	352	340	340	340	138	102	68	46
Actual costs inc. Capex	$m		-363	-271	-275	-159	-139	-134	-109	-109	-109	-109	-109	-109	-109	-109	-104	-104	-42	-31	-21	-14
Net field cashflow	$m		**-138**	**184**	**73**	**319**	**429**	**351**	**355**	**326**	**300**	**261**	**262**	**243**	**243**	**232**	**237**	**237**	**96**	**71**	**47**	**32**
Net Tullow cashflow	$m		**-15**	**20**	**8**	**35**	**47**	**39**	**39**	**36**	**33**	**29**	**29**	**27**	**27**	**26**	**26**	**26**	**11**	**8**	**5**	**4**

Actual Costs			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E
Variable production costs/bbl		$/bbl	**6,3**	**5,9**	**8,5**	**9,0**	**10,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**	**13,0**
Production costs		$m	33	51	88	99	99	104	104	104	104	104	104	104	104	104	104	104	42	31	21	14
Capex	907	$m	330	220	187	60	40	30	5	5	5	5	5	5	5	5	0	0	0	0	0	0
Abandonment costs		$m																				0
Total costs		**$m**	**363**	**271**	**275**	**159**	**139**	**134**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**109**	**104**	**104**	**42**	**31**	**21**	**14**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	2241	$m
Remaining NPV- Tullow	247	$m
EV / 2P remaining WI	26	$/ boe WI
Discount rate	8,9%	
Reserves data- on 2P basis		
Gross remaining reserves	88	mboe
Working interest reserves	10	mboe

PSC - Oil Production		
	Production	**contractor share**
kboe/d	50	50%
kboe/d	100	45%
kboe/d	150	40%
kboe/d	> 150	35%

Appendix 30 - DCF Mauritania - Chinguetti

Mauritania - Chinguetti PRODUCING
Tullow WI 22%

Production assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Field production	**kboe/d**	15	12	11	8	6	6	6	6	6	6	6	0	0	0
Cumulative production	mboe	14	19	23	26	28	30	32	34	36	38	41	41	41	41

Pricing assumption		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Oil Price (Brent)	$/bbl	72	97	63	80	111	118	113	106	100	95	95	95	95	95
Discount to Brent	$/bbl	1	1	7	7	7	7	7	7	7	7	7	7	7	7
Realised oil price	$/bbl	71	96	56	73	104	111	106	99	93	88	88	88	88	88

Revenue calculation		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Gross revenue	$m	386	412	219	213	239	237	226	211	197	187	188	0	0	0
Less royalty rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Recoverd Costs inc Capex		-193	-124	-44	-43	-48	-36	-34	-32	-30	0	0	0	0	0
Profit Available		193	288	175	171	191	202	192	179	168	187	188	0	0	0
Profit share	0%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Total profit for operators		125	187	114	111	124	131	125	117	109	122	122	0	0	0
Contract revenues		318	311	158	153	172	167	159	148	139	122	122	0	0	0
Tullow Share		**71**	**69**	**35**	**34**	**38**	**37**	**35**	**33**	**31**	**27**	**27**	**0**	**0**	**0**

Contractor take of cashflows		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Contractor revenues (after royalties)	$m	318	311	158	153	172	167	159	148	139	122	122	0	0	0
Actual costs inc. Capex	$m	-104	-77	-99	-78	-81	-117	-88	-44	-44	-44	-44	0	0	0
Depreciation per barrel	$/bll	**3**	**3**	**3**	**3**	**3**	11	11	11	11	11	11	11		
Depreciation for tax purpose	$m	16	13	12	9	7	23	23	23	23	23	23	0		
Tax	25%	49	55	12	17	21	6	12	20	18	14	14	0	0	0
Net field cashflow	$m	**164**	**179**	**47**	**59**	**70**	**43**	**59**	**84**	**77**	**64**	**64**	**0**	**0**	**0**
Net Tullow cashflow	$m	**37**	**40**	**10**	**13**	**16**	**10**	**13**	**19**	**17**	**14**	**14**	**0**	**0**	**0**

Actual Costs			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Variable production costs/bbl		$/bbl	19,3	18,0	25,2	26,6	35,1	55,0	41,3	20,6	20,6	20,6	20,6	20,6	20,6	20,6
Production costs	820	$m	104	77	99	78	81	117	88	44	44	44	44	0	0	0
Capex	395	$m		395	0	0	0	0	0	0	0	0	0	0	0	0
Exploration	43	$m		43	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs	0	$m											0			
Total costs	1258	**$m**	**104**	**515**	**99**	**78**	**81**	**117**	**88**	**44**	**44**	**44**	**44**	**0**	**0**	**0**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	294	$m
Remaining NPV- Tullow	65	$m
EV / 2P remaining WI	23	$/ boe WI
Discount rate	8,9%	
Reserves data- on 2P basis		
Gross remaining reserves	13	mboe
Working interest reserves	3	mboe

PSC - Oil Production		
	Production	**Contractor Share**
kboe/d	25	65%
kboe/d	75	60%
kboe/d	100	55%
kboe/d	>100	50%

Source: Company Data Mauritania, NAV Model

Appendix 31 - DCF Mauritania - TIOF

Mauritania TIOF
Working Interest 22%

Production assumption			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Production profile	250	mmboe	0%	0%	0%	2%	8%	11%	12%	14%	12%	10%	8%	7%	5%	5%	5%	1%
Field production		**kboe/d**	**0**	**0**	**0**	**14**	**55**	**75**	**82**	**92**	**82**	**68**	**55**	**48**	**34**	**34**	**34**	**7**
Cumulative production		mboe	0	0	0	5	25	53	83	116	146	171	191	209	221	234	246	249

Pricing assumption			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Oil Price (Brent)	$/bbl		118	113	106	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	7	7	7	7	7	7	7
Realised oil price	$/bbl		118	113	105	95	94	95	95	95	95	102	102	102	102	102	102	102

Revenue calculation			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Gross revenue	$m		0	0	0	473	1883	2599	2835	3189	2835	2550	2040	1785	1275	1275	1275	255
Recoverd Costs inc Capex						-189	-942	-780	-567	-638	-567	-383	-306	-268	-191	-191	-128	-26
Profit Available			0	0	0	284	942	1819	2268	2552	2268	2168	1734	1517	1084	1084	1148	230
Profit share	0%		65%	65%	65%	65%	60%	55%	55%	55%	55%	60%	60%	60%	60%	60%	60%	65%
Total profit for operators			0	0	0	184	565	1001	1247	1403	1247	1301	1040	910	650	650	689	149
Tullow Share			**0**	**0**	**0**	**41**	**126**	**223**	**278**	**312**	**278**	**289**	**231**	**203**	**145**	**145**	**153**	**33**

Contractor take of cashflows			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Contractor revenues (after royalties)	$m		0	0	0	373	1507	1780	1814	2041	1814	1683	1346	1178	842	842	816	175
Actual costs inc. Capex	$m		0	-450	-788	-863	-525	-413	-450	-506	-450	-375	-300	-263	-188	-188	-188	-38
Tax			-3	-3	-3	-91	-359	-420	-426	-479	-426	-399	-319	-280	-201	-201	-194	-44
Net field cashflow	$m		**-3**	**-453**	**-790**	**-580**	**622**	**947**	**938**	**1056**	**938**	**910**	**727**	**636**	**453**	**453**	**434**	**93**
Net Tullow cashflow	$m		**-1**	**-98**	**-171**	**-125**	**134**	**205**	**203**	**228**	**203**	**196**	**157**	**137**	**98**	**98**	**94**	**20**

Tax			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Revenue gross	$m		0	0	0	473	1883	2599	2835	3189	2835	2550	2040	1785	1275	1275	1275	255
Less costs	$m		0	0	0	-75	-300	-413	-450	-506	-450	-375	-300	-263	-188	-188	-188	-38
			11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Less depreciation	$m		0	0	0	55	220	303	330	371	330	275	220	193	138	138	138	28
Profit share			0	0	0	-99	-377	-819	-1021	-1148	-1021	-867	-694	-607	-434	-434	-459	-80
Taxable base	$m		11	11	11	364	1438	1681	1705	1917	1705	1594	1277	1119	803	803	777	176
Tax rate	25%	%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Tax	**$m**		**-3**	**-3**	**-3**	**-91**	**-359**	**-420**	**-426**	**-479**	**-426**	**-399**	**-319**	**-280**	**-201**	**-201**	**-194**	**-44**
Variable production costs/bbl	$/boe		15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0	15,0
Production costs			0	0	0	75	300	413	450	506	450	375	300	263	188	188	188	38

Actual Costs			2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Production costs	3131,25	$m	0	0	0	75	300	413	450	506	450	375	300	263	188	188	188	38
Capex	2250	$m	0	450	788	788	225	0	0	0	0	0	0	0	0	0	0	0
Exploration	0	$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs	0	$m						0					0				0	
Total costs	5381	**$m**	**0**	**450**	**788**	**863**	**525**	**413**	**450**	**506**	**450**	**375**	**300**	**263**	**188**	**188**	**188**	**38**
Capex phasing	.W guidance		0%	20%	35%	35%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Capex/bbl	9																	

VALUATION	PV OF EV FCF	
Remaining NPV - gross	2395	$m
Remaining NPV- Tullow	517	$m
EV / 2P remaining WI	9,63	$/ boe WI
Discount rate	8,9%	
Reserves data- on 2P basis		
Gross remaining reserves	249	mboe
Working interest reserves	54	mboe

Mauritania - Chinguetti PRODUCING		22%	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
Net Production		kboe/d	3	3	2	2	1	1	1	1	1	1	1	0	0	0
Net revenues		$m	71	69	35	34	38	37	35	33	31	27	27	0	0	0
Net opex		$m	-23	-17	-22	-17	-18	-26	-20	-10	-10	-10	-10	0	0	0
Net capex		$m	0	-88	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	-11	-12	-3	-4	-5	-1	-3	-4	-4	-3	-3	0	0	0
Net cash		$m	37	-48	10	13	16	10	13	19	17	14	14	0	0	0

Mauritania TIOF		22%	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E
Net Production		kboe/d	0	0	0	3	12	16	18	20	18	15	12	10	7	7	7	1
Net revenues		$m	0	0	0	81	325	385	392	441	392	364	291	254	182	182	176	38
Net opex		$m	0	0	-16	-65	-89	-97	-109	-97	-81	-65	-57	-41	-41	-41	-8	0
Net capex		$m	-97	-170	-170	-49	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	-20	-78	-91	-92	-104	-92	-86	-69	-60	-43	-43	-42	-9
Net cash		$m	-97	-170	-186	-52	159	197	190	240	219	213	165	154	98	98	126	28

TULLOW OIL

Appendix 32 - DCF Sierra Leone

Sierra Leone		**Offshore**
Tullow Working Interst		**20%**
Royalty		**7%**

Production	**Total**		**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**
Field production profile	1000	99%	**0%**	**0%**	**0%**	**0%**	5,0%	12,2%	9,0%	8,0%	5,0%	4,9%	4,8%	4,5%	4,3%	4,0%	3,9%	3,8%	3,7%	3,6%	3,5%	3,4%	3,3%	3,2%	3,1%	3,0%	2,9%	1,0%	1,0%	0,9%
Field production		kboe/d	0,0	0	0	0	137	334	247	219	137	134	132	123	118	110	107	104	101	99	96	93	90	88	85	82	79	27	27	25
Production growth								144%	-26%	-11%	-38%	-2%	-2%	-6%	-4%	-7%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-66%	0%	-10%
Cumulative production		mboe	0	0	0	0	50	172	262	342	392	441	489	534	577	617	656	694	731	767	802	836	869	901	932	962	991	1001	1011	1020
Pricing assumption			**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**
Oil Price (Brent)	$/bbl		111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Revenue calculation			**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**
Gross revenue	$m		0	0	0	0	4976	11531	8550	7600	4750	4655	4560	4275	4085	3800	3705	3610	3515	3420	3325	3230	3135	3040	2945	2850	2755	950	950	855
Tullow Share			**0**	**0**	**0**	**0**	**995**	**2306**	**1710**	**1520**	**950**	**931**	**912**	**855**	**817**	**760**	**741**	**722**	**703**	**684**	**665**	**646**	**627**	**608**	**589**	**570**	**551**	**190**	**190**	**171**
Gross Field FCF calculation			**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**
Gross Revenue	97067	$m	0	0	0	0	4976	11531	8550	7600	4750	4655	4560	4275	4085	3800	3705	3610	3515	3420	3325	3230	3135	3040	2945	2850	2755	950	950	855
Royalty		$m	0	0	0	0	-323	-750	-556	-494	-309	-303	-296	-278	-266	-247	-241	-235	-228	-222	-216	-210	-204	-198	-191	-185	-179	-62	-62	-56
Post royalty revenues		$m	0	0	0	0	4652	10782	7994	7106	4441	4352	4264	3997	3819	3553	3464	3375	3287	3198	3109	3020	2931	2842	2754	2665	2576	888	888	799
Production costs	-9185	$m	0	0	0	0	-450	-1097	-811	-720	-450	-441	-432	-405	-387	-360	-351	-342	-333	-324	-315	-306	-297	-288	-279	-270	-261	-90	-90	-81
Capex		$m	0	-1470	-4900	-3430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	0	-1470	-4900	-3430	4202	9685	7184	6386	3991	3911	3831	3592	3432	3193	3113	3033	2953	2873	2794	2714	2634	2554	2474	2395	2315	798	798	718
Tax		$m	0	88	382	588	-673	-2317	-1655	-1710	-1197	-1173	-1149	-1078	-1030	-958	-934	-910	-886	-862	-838	-814	-790	-766	-742	-718	-694	-239	-239	-216
Net contractor cashflow		$m	0	-1382	-4518	-2842	3529	7367	5528	4676	2794	2738	2682	2514	2403	2235	2179	2123	2067	2011	1956	1900	1844	1788	1732	1676	1620	559	559	503
Tullow working interest		%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Net Tullow cashflow		**$m**	**0**	**-276**	**-904**	**-568**	**706**	**1473**	**1106**	**935**	**559**	**548**	**536**	**503**	**481**	**447**	**436**	**425**	**413**	**402**	**391**	**380**	**369**	**358**	**346**	**335**	**324**	**112**	**112**	**101**

VALUE	PV of EV FCF	
Gross field	18500	$m
TLW	3700	$m
EV / 2P remaining working interest	18,7	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	1000	mboe
Remaining gross reserves	991	mboe
Remaining reserves working interest	198	mboe

Tax			2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Revenue post royalty		$m	0	0	0	0	4652	10782	7994	7106	4441	4352	4264	3997	3819	3553	3464	3375	3287	3198	3109	3020	2931	2842	2754	2665	2576	888	888	799
Less costs		$m	0	0	0	0	-450	-1097	-811	-720	-450	-441	-432	-405	-387	-360	-351	-342	-333	-324	-315	-306	-297	-288	-279	-270	-261	-90	-90	-81
Less depreciation		$m	0	-294	-1274	-1960	-1960	-1960	-1666	-686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxable base		$m	0	-294	-1274	-1960	2242	7725	5518	5700	3991	3911	3831	3592	3432	3193	3113	3033	2953	2873	2794	2714	2634	2554	2474	2395	2315	798	798	718
Tax rate	30%	%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Tax		**$m**	**0**	**-88**	**-382**	**-588**	**673**	**2317**	**1655**	**1710**	**1197**	**1173**	**1149**	**1078**	**1030**	**958**	**934**	**910**	**886**	**862**	**838**	**814**	**790**	**766**	**742**	**718**	**694**	**239**	**239**	**216**

Capex & depreciation	Total		2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized capex	9800	$m	0	0	1176	4802	6272	4312	2352	686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capex added	9800	$m	0	1470	4900	3430	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%	-20%	$m	0	-294	-1274	-1960	-1960	-1960	-1666	-686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Closing NBV		$m	0	1176	4802	6272	4312	2352	686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capex phasing	W guidance	100%		15%	50%	35%																								
Capex	10	$/boe																												
Abandonment costs	1,0																													
Capex check																														

Tullow Equity		20%	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	
Net Production		**kboe/d**	0	0	0	0	27	67	49	44	27	27	26	25	24	22	21	21	20	20	19	19	18	18	17	16	16	5	5	5
Net revenues		$m	0	0	0	0	995	2306	1710	1520	950	931	912	855	817	760	741	722	703	684	665	646	627	608	589	570	551	190	190	171
Net opex		$m	0	0	0	0	-90	-219	-162	-144	-90	-88	-86	-81	-77	-72	-70	-68	-67	-65	-63	-61	-59	-58	-56	-54	-52	-18	-18	-16
Net capex		$m	0	-294	-980	-686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	18	76	118	-199	-613	-442	-441	-301	-295	-289	-271	-259															
Net cash		$m	0	-276	-904	-568	706	1473	1106	935	559	548	536	503	481	688	671	654	636	619	602	585	568	550	533	516	499	172	172	155

Appendix 33 - DCF Liberia

Liberia	
Tullow	100%
Royalty	PSC

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Field production profile	1000	97%			0,0%	0,0%	0%	0%	0%	3%	12,2%	9,0%	8,0%	5,0%	4,9%	4,8%	4,5%	4,3%	4,0%	3,9%	3,8%	3,7%	3,6%	3,5%	3,4%	3,3%	3,2%	3,1%	3,0%	2,9%	1,0%	1,0%	0,9%
Field production		kboe/d	0	0	0	0	0	0	0	82	334	247	219	137	134	132	123	118	110	107	104	101	99	96	93	90	88	85	82	79	27	27	25
Production growth											306%	-26%	-11%	-38%	-2%	-2%	-6%	-4%	-7%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-66%	0%	-10%
Cumulative production		mboe	0	0	0	0	0	0	0	30	152	242	322	372	421	469	514	557	597	636	674	711	747	782	816	849	881	912	942	971	981	991	1000

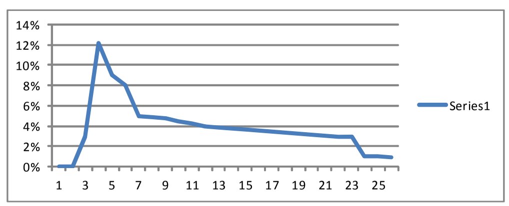
Pricing assumption		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Oil Price (Brent)	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Profit Oil calculation		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Gross revenue (before royalty)	$m	0	0	0	0	0	0	0	2985	11531	8550	7600	4750	4655	4560	4275	4085	3800	3705	3610	3515	3420	3325	3230	3135	3040	2945	2850	2755	950	950	855
Recovered costs inc. capex	$m	0	0	0	0	0	0	0	-2388	-5766	-2565	-1520	-950	-931	-684	-641	-613	-570	-556	-361	-352	-171	-166	-162	-63	-61	-59	-57	0	0	0	0
Profit oil available	$m	0	0	0	0	0	0	0	597	5766	5985	6080	3800	3724	3876	3634	3472	3230	3149	3249	3164	3249	3159	3069	3072	2979	2886	2793	2755	950	950	855
Profit share (contractor)	%	60%	60%	60%	60%	60%	60%	60%	60%	40%	40%	40%	50%	50%	50%	50%	50%	50%	50%	50%	50%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
Total profit oil for contractors	$m	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**358**	**2306**	**2394**	**2432**	**1900**	**1862**	**1938**	**1817**	**1736**	**1615**	**1575**	**1625**	**1582**	**1949**	**1895**	**1841**	**1843**	**1788**	**1732**	**1676**	**1653**	**570**	**570**	**513**

Contractor take of cashflows		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Contractor revenues	$m	0	0	0	0	0	0	0	2747	8072	4959	3952	2850	2793	2622	2458	2349	2185	2130	1986	1933	2120	2062	2003	1906	1848	1791	1733	1653	570	570	513
Actual costs inc. capex	$m	0	0	0	0	-1500	-5000	-3500	-228	-926	-684	-608	-380	-372	-365	-342	-327	-304	-296	-289	-281	-274	-266	-258	-251	-243	-236	-228	-220	-76	-76	-68
Income tax	$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net contractor cashflow	$m	**0**	**0**	**0**	**0**	**-1500**	**-5000**	**-3500**	**2519**	**7146**	**4275**	**3344**	**2470**	**2421**	**2257**	**2116**	**2022**	**1881**	**1834**	**1697**	**1652**	**1847**	**1796**	**1744**	**1655**	**1605**	**1555**	**1505**	**1433**	**494**	**494**	**445**
Tullow equity	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow	$m	**0**	**0**	**0**	**0**	**-1500**	**-5000**	**-3500**	**2519**	**7146**	**4275**	**3344**	**2470**	**2421**	**2257**	**2116**	**2022**	**1881**	**1834**	**1697**	**1652**	**1847**	**1796**	**1744**	**1655**	**1605**	**1555**	**1505**	**1433**	**494**	**494**	**445**

VALUE	PV of EV FCF	
Gross field	12113	$m
TLW	12113	$m
EV / 2P remaining working i	12,5	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	1000	mboe
Remaining gross reserves	971	mboe
Remaining reserves workin	971	mboe

Profit oil share		
	Production	contractor share %
kboe/d	100	60,0%
kboe/d	150	50,0%
kboe/d	> 150	40,0%



Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Revenue		$m	0	0	0	0	0	0	0	2985	11531	8550	7600	4750	4655	4560	4275	4085	3800	3705	3610	3515	3420	3325	3230	3135	3040	2945	2850	2755	950	950	855
Less costs		$m	0	0	0	0	0	0	0	-228	-926	-684	-608	-380	-372	-365	-342	-327	-304	-296	-289	-281	-274	-266	-258	-251	-243	-236	-228	-220	-76	-76	-68
Less depreciation		$m	0	0	0	0	-150	-770	-1466	-1523	-1218	-975	-780	-624	-499	-399	-319	-255	-204	-164	-131	-105	-84	-67	-54	-43	-34	-27	-22	-18	-14	-11	-9
Gvmt share		$m		0	0	0	0	0	0	-239	-3459	-3591	-3648	-1900	-1862	-1938	-1817	-1736	-1615	-1575	-1625	-1582	-1300	-1264	-1227	-1229	-1192	-1154	-1117	-1102	-380	-380	-342
Taxable base		$m	0	0	0	0	-150	-770	-1466	996	5928	3300	2564	1846	1922	1858	1797	1767	1677	1670	1566	1547	1763	1729	1691	1612	1571	1528	1483	1415	480	483	436
Tax rate	0%	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized	10000	$m	0	0	0	0	0	1350	5580	7614	6091	4873	3898	3119	2495	1996	1597	1277	1022	818	654	523	419	335	268	214	171	137	110	88	70	56	45
Capex added	10000	$m	0	0	0	0	1500	5000	3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	-150	-770	-1466	-1523	-1218	-975	-780	-624	-499	-399	-319	-255	-204	-164	-131	-105	-84	-67	-54	-43	-34	-27	-22	-18	-14	-11	-9
Closing NBV		$m	0	0	0	0	1350	5580	7614	6091	4873	3898	3119	2495	1996	1597	1277	1022	818	654	523	419	335	268	214	171	137	110	88	70	56	45	36
Capex phasing	W guidance	100%	0%	0%	0%	0%	15%	50%	35%	0%	0%	0%	0%	0%	0%	0%	0%																
Capex	10	$/boe																															
Abandonment costs	1,0																																
Capex check																																	

Actual Costs			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Variable production costs/bbl		$/bbl	0,0	7,0	6,7	7,0	7,3	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6	7,6
Production costs		$m	0	0	0	0	0	0	0	228	926	684	608	380	372	365	342	327	304	296	289	281	274	266	258	251	243	236	228	220	76	76	68
Capex Including Exploration	10000	$m	0	0	0	0	1500	5000	3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exploration		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs																																	
Total costs		**$m**	**0**	**0**	**0**	**0**	**1500**	**5000**	**3500**	**228**	**926**	**684**	**608**	**380**	**372**	**365**	**342**	**327**	**304**	**296**	**289**	**281**	**274**	**266**	**258**	**251**	**243**	**236**	**228**	**220**	**76**	**76**	**68**

Tullow Equity		100%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Net Production		**kboe/d**	0	0	0	0	0	0	0	82	334	247	219	137	134	132	123	118	110	107	104	101	99	96	93	90	88	85	82	79	27	27	25
Net revenues		$m	0	0	0	0	0	0	0	2747	8072	4959	3952	2850	2793	2622	2458	2349	2185	2130	1986	1933	2120	2062	2003	1906	1848	1791	1733	1653	570	570	513
Net opex		$m	0	0	0	0	0	0	0	-228	-926	-684	-608	-380	-372	-365	-342	-327	-304	-296	-289	-281	-274	-266	-258	-251	-243	-236	-228	-220	-76	-76	-68
Net capex		$m	0	0	0	0	-1500	-5000	-3500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net cash		$m	0	0	0	0	-1500	-5000	-3500	2519	7146	4275	3344	2470	2421	2257	2116	2022	1881	1834	1697	1652	1847	1796	1744	1655	1605	1555	1505	1433	494	494	445

Appendix 34 - DCF Ghana – Jubilee Phase 1&1a

Jubilee Phase 1&1a Offshore Ghana	
Tullow WI	35%
Royalty	5%

Tullow Working Interests Ghana

Partner	Deep Tano	WC3	Phase 1&1a	Phase 1b
Tullow Oil	49,95%	26,4%	35,5%	38,2%

Source: Tullow Oil, Group Licence Interests

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Field production profile	470	95%		0,0%	0,1%	5,1%	6,2%	8,5%	8,5%	8,5%	8,5%	7,5%	7,5%	5,5%	4,8%	4,0%	3,5%	3,0%	2,8%	2,5%	2,4%	2,3%	2,2%	2,0%	0,0%
Field production		kboe/d	0	0	1,3	66,2	80	109	109	109	109	97	97	71	62	52	45	39	36	32	31	30	28	26	0
Production growth						5044%	21%	37%	0%	0%	0%	-12%	0%	-27%	-13%	-17%	-13%	-14%	-7%	-11%	-4%	-4%	-4%	-9%	-100%
Cumulative production		mboe	0	0	0	25	54	94	134	174	214	249	284	310	333	351	368	382	395	407	418	429	439	449	449

Source: Own calculations, NAV model

Pricing assumption		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Oil Price (Brent)	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Revenue calculation		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross revenue	$m	0	0	38	2682	3454	4520	4230	3976	3782	3349	3349	2456	2143	1786	1563	1340	1250	1116	1072	1027	982	893	0
Tullow Share		**0**	**0**	**13**	**951**	**1225**	**1604**	**1501**	**1411**	**1342**	**1188**	**1188**	**871**	**760**	**634**	**554**	**475**	**444**	**396**	**380**	**364**	**349**	**317**	**0**

Gross Field FCF calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross Revenue	43707	$m	0	0	38	2682	3454	4520	4230	3976	3782	3349	3349	2456	2143	1786	1563	1340	1250	1116	1072	1027	982	893	0
Royalty		$m	0	0	-2	-134	-173	-226	-212	-199	-189	-167	-167	-123	-107	-89	-78	-67	-63	-56	-54	-51	-49	-45	0
Post royalty revenues		$m	0	0	36	2548	3281	4294	4019	3777	3592	3181	3181	2333	2036	1697	1485	1273	1188	1060	1018	976	933	848	0
Production costs	-4403	$m	0	0	-4	-160	-292	-400	-400	-400	-400	-353	-353	-259	-226	-188	-165	-141	-132	-118	-113	-108	-103	-94	0
Capex		$m	-222	-986	-1208	-1399	-1083	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	-222	-986	-1175	989	1906	3894	3619	3377	3193	2829	2829	2074	1810	1508	1320	1132	1056	943	905	868	830	754	0
Tax		$m	16	47	103	-653	-813	-1139	-1087	-1039	-1003	-898	-917	-667	-587	-490	-432	-372	-350	-315	-304	-294	-283	-258	5
Net field cashflows before APT		$m	-206	-939	-1072	336	1093	2756	2532	2339	2190	1931	1912	1407	1223	1018	888	760	706	628	601	574	547	497	5
Additional Profit tax ESTIMATE	#####	$m	0	0	0	0	0	0	-633	-585	-548	-483	-478	-352	-306	-254	-222	-190	-176	-157	-150	-143	-137	-124	-1
Net contractor cashflow		$m	-206	-939	-1072	336	1093	2756	1899	1754	1643	1448	1434	1055	918	763	666	570	529	471	451	430	410	372	4
Tullow working interest		%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Net Tullow cashflow		**$m**	**-73**	**-333**	**-380**	**119**	**388**	**978**	**674**	**622**	**583**	**514**	**509**	**374**	**326**	**271**	**236**	**202**	**188**	**167**	**160**	**153**	**146**	**132**	**1**

VALUE	PV of EV FCF	
Gross field	12278	$m
TLW	4356	$m
EV / 2P remaining w orking interest	27,4	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	470	mboe
Remaining gross reserves	448	mboe
Remaining reserves w orking interest	159	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Revenue post royalty		$m	0	0	36	2548	3281	4294	4019	3777	3592	3181	3181	2333	2036	1697	1485	1273	1188	1060	1018	976	933	848	0
Less costs		$m	0	0	-4	-160	-292	-400	-400	-400	-400	-353	-353	-259	-226	-188	-165	-141	-132	-118	-113	-108	-103	-94	0
Less depreciation		$m	-44	-134	-327	-522	-666	-641	-513	-410	-328	-263	-210	-168	-135	-108	-86	-69	-55	-44	-35	-28	-23	-18	-14
Taxable base		$m	-44	-134	-294	1866	2323	3253	3107	2967	2865	2566	2619	1906	1676	1401	1234	1063	1001	899	870	839	807	736	-14
Tax rate	35%	%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax		**$m**	**-16**	**-47**	**-103**	**653**	**813**	**1139**	**1087**	**1039**	**1003**	**898**	**917**	**667**	**587**	**490**	**432**	**372**	**350**	**315**	**304**	**294**	**283**	**258**	**-5**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Starting NBV of capitalized capex	4898	$m	0	177	1029	1910	2787	3205	2564	2051	1641	1313	1050	840	672	538	431	345	276	221	177	141	113	90	72
Capex added	4430	$m	222	986	1208	1399	1083	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	-44	-134	-327	-522	-666	-641	-513	-410	-328	-263	-210	-168	-135	-108	-86	-69	-55	-44	-35	-28	-23	-18	-14
Closing NBV		$m	177	1029	1910	2787	3205	2564	2051	1641	1313	1050	840	672	538	431	345	276	221	177	141	113	90	72	58
Capex phasing	ıidance	100%	**5%**	**20%**	**25%**	**30%**	**17%**	**3%**																	
Capex	9	$/boe																							
Abandonment costs	1,0																								
Capex check																									

Tullow Equity	35%	2007A	2008A	2009A	2010A	2011E	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E
Net Production	**kboe/d**	0	0	0	0	23,5	28	39	39	39	39	34	34	25	22	18	16	14	13	11	11	11	10	9
Net revenues	$m	0	0	0	13	951	1225	1604	1501	1411	1342	1188	1188	871	760	634	554	475	444	396	380	364	349	317
Net opex	$m	0	0	0	-1	-57	-104	-142	-142	-142	-142	-125	-125	-92	-80	-67	-58	-50	-47	-42	-40	-38	-37	-33
Net capex	$m	0	-79	-350	-428	-496	-384	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax	$m	0	0	36	-279	-350	-484	-685	-646	-617	-549	-554	-405	-355	-296	-260	-223	-209	-187	-180	-173	-166	-151	0
Net cash	$m	0	-79	-314	-696	49	253	776	713	652	651	509	658	425	384	307	273	216	210	174	167	160	161	283

Appendix 35 - DCF Ghana – Jubilee Phase 1b

Jubilee Phase 1b	Offshore	Ghana
Tullow WI		38%
Royalty		5%

NB! Due to aquisition, and increase in the DWT area --> 49,95%

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Field production profile	205	101%			0,0%	0,0%	0,0%	0,0%	0,0%	9,0%	15,0%	15,0%	15,0%	14,0%	8,0%	5,0%	4,0%	3,4%	3,2%	3,1%	3,0%	1,9%	1,0%	0,0%	0,0%
Field production		kboe/d	0	0	0	0	0	0	0	51	84	84	84	79	45	28	22	19	18	17	17	11	6	0	0
Production growth											67%	0%	0%	-7%	-43%	-38%	-20%	-15%	-6%	-3%	-3%	-37%	-47%	-100%	
Cumulative production		mboe	0	0	0	0	0	0	0	18	49	80	111	139	156	166	174	181	188	194	200	204	206	206	206
Jubilee Phases 1, 1a and 1b			0	0	1	66	80	109	109	160	194	181	181	149	107	80	68	58	54	50	48	40	34	26	0

Pricing assumption			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Oil Price (Brent)	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Revenue calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross revenue	$m		0	0	0	0	0	0	0	1836	2911	2921	2921	2727	1558	974	779	662	623	604	584	370	195	0	0
Tullow Share			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**701**	**1112**	**1116**	**1116**	**1042**	**595**	**372**	**298**	**253**	**238**	**231**	**223**	**141**	**74**	**0**	**0**

Gross Field FCF calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross Revenue	43707	$m	0	0	0	0	0	0	0	1836	2911	2921	2921	2727	1558	974	779	662	623	604	584	370	195	0	0
Royalty		$m	0	0	0	0	0	0	0	-92	-146	-146	-146	-136	-78	-49	-39	-33	-31	-30	-29	-19	-10	0	0
Post royalty revenues		$m	0	0	0	0	0	0	0	1744	2765	2775	2775	2590	1480	925	740	629	592	574	555	352	185	0	0
Production costs	-2062	$m	0	0	0	0	0	0	0	-185	-308	-308	-308	-287	-164	-103	-82	-70	-66	-64	-62	-39	-21	0	0
Capex		$m	0	0	0	0	0	-205	-410	-410	-820	-205	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	0	0	0	0	0	-205	-410	1150	1638	2263	2468	2303	1316	823	658	559	526	510	494	313	165	0	0
Tax		$m	0	0	0	0	0	7	27	-495	-777	-761	-774	-735	-403	-242	-194	-167	-161	-160	-158	-97	-48	8	6
Net field cashflows before APT		$m	0	0	0	0	0	-198	-383	654	861	1502	1693	1568	913	580	464	393	366	350	336	215	117	8	6
Additional Profit tax ESTIMATE	25,00%	$m	0	0	0	0	0	0	96	-164	-215	-375	-423	-392	-228	-145	-116	-98	-91	-88	-84	-54	-29	-2	-2
Net contractor cashflow		$m	0	0	0	0	0	-198	-287	491	646	1126	1270	1176	684	435	348	295	274	263	252	161	87	6	5
Tullow working interest		%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%	38%
Net Tullow cashflow		**$m**	**0**	**0**	**0**	**0**	**0**	**-76**	**-110**	**187**	**247**	**430**	**485**	**449**	**261**	**166**	**133**	**113**	**105**	**100**	**96**	**62**	**33**	**2**	**2**

VALUE	PV of EV FCF	
Gross field	3714	$m
TLW	1419	$m
EV / 2P remaining working interest	18,0	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	205	mboe
Remaining gross reserves	206	mboe
Remaining reserves working interest	79	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Revenue post royalty		$m	0	0	0	0	0	0	0	1744	2765	2775	2775	2590	1480	925	740	629	592	574	555	352	185	0	0
Less costs		$m	0	0	0	0	0	0	0	-185	-308	-308	-308	-287	-164	-103	-82	-70	-66	-64	-62	-39	-21	0	0
Less depreciation		$m	0	0	0	0	0	-21	-78	-144	-238	-293	-255	-204	-163	-131	-104	-84	-67	-54	-43	-34	-27	-22	-18
Taxable base		$m	0	0	0	0	0	-21	-78	1415	2219	2174	2213	2099	1153	692	554	476	460	456	451	278	137	-22	-18
Tax rate	35%	%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**-7**	**-27**	**495**	**777**	**761**	**774**	**735**	**403**	**242**	**194**	**167**	**161**	**160**	**158**	**97**	**48**	**-8**	**-6**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Starting NBV of capitalized capex	2050	$m	0	0	0	0	0	0	185	517	782	1364	1276	1020	816	653	522	418	334	268	214	171	137	110	88
Capex added	2050	$m	0	0	0	0	0	205	410	410	820	205	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	0	-21	-78	-144	-238	-293	-255	-204	-163	-131	-104	-84	-67	-54	-43	-34	-27	-22	-18
Closing NBV		$m	0	0	0	0	0	185	517	782	1364	1276	1020	816	653	522	418	334	268	214	171	137	110	88	70
Capex phasing	TLW guidance	100%						10%	20%	20%	40%	10%													
Capex	10	$/boe																							
Abandonment costs	1,0																								
Capex check																									

Tullow Equity		38%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Net Production		**kboe/d**	0	0	0	0	0	0	0	19	32	32	32	30	17	11	9	7	7	7	6	4	2	0	0
Net revenues		$m	0	0	0	0	0	0	0	701	1112	1116	1116	1042	595	372	298	253	238	231	223	141	74	0	0
Net opex		$m	0	0	0	0	0	0	0	-70	-117	-117	-117	-110	-63	-39	-31	-27	-25	-24	-23	-15	-8	0	0
Net capex		$m	0	0	0	0	0	-78,31	-156,6	-156,6	-313,2	-78,31	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	-287	-435	-490	-513	-483	-271	-167	-133	-114	-108	-106	-103	-65	-33	0	0
Net cash		$m	0	0	0	0	0	-78	-157	187	247	430	485	449	261	166	133	113	105	100	96	62	33	0	0

Appendix 36 - DCF Ghana – TEN prospects

TEN Offshore	**Ghana**	
Tullow WI		**49,95%**
Royalty		**5%**

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Field production profile	280	100%			0,0%	0,0%	0,0%	0,0%	0,0%	5,0%	12,0%	12,0%	12,0%	12,0%	12,0%	9,6%	7,7%	6,1%	4,9%	3,9%	3,1%	0,0%	0,0%	0,0%	0,0%
Field production		kboe/d	0	0	0	0	0	0	0	38	92	92	92	92	92	74	59	47	38	30	24	0	0	0	0
Production growth											140%	0%	0%	0%	0%	-20%	-20%	-20%	-20%	-20%	-20%	-100%			
Cumulative production		mboe	0	0	0	0	0	0	0	14	48	81	115	148	182	209	230	248	261	272	281	281	281	281	281
Jubilee Phases 1, 1a and 1b			0	0	1	66	80	109	109	148	202	189	189	163	154	125	104	86	74	62	55	30	28	26	0

Pricing assumption		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Oil Price (Brent)	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Revenue calculation		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross revenue	$m	0	0	0	0	0	0	0	1393	3180	3192	3192	3192	3192	2554	2043	1634	1307	1046	837	0	0	0	0
Tullow Share		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**696**	**1589**	**1594**	**1594**	**1594**	**1594**	**1276**	**1020**	**816**	**653**	**522**	**418**	**0**	**0**	**0**	**0**

Gross Field FCF calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross Revenue	43707	$m	0	0	0	0	0	0	0	1393	3180	3192	3192	3192	3192	2554	2043	1634	1307	1046	837	0	0	0	0
Royalty		$m	0	0	0	0	0	0	0	-70	-159	-160	-160	-160	-160	-128	-102	-82	-65	-52	-42	0	0	0	0
Post royalty revenues		$m	0	0	0	0	0	0	0	1324	3021	3032	3032	3032	3032	2426	1941	1553	1242	994	795	0	0	0	0
Production costs	-2812	$m	0	0	0	0	0	0	0	-140	-336	-336	-336	-336	-336	-269	-215	-172	-138	-110	-88	0	0	0	0
Capex		$m	0	0	0	0	-56	-700	-840	-560	-364	-280	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	0	0	0	0	-56	-700	-840	624	2321	2416	2696	2696	2696	2157	1726	1381	1104	884	707	0	0	0	0
Tax		$m	0	0	0	0	2	28	76	-304	-820	-825	-839	-860	-877	-701	-561	-449	-359	-287	-230	14	11	9	7
Net field cashflows before APT		$m	0	0	0	0	-54	-672	-764	319	1502	1592	1858	1837	1820	1456	1165	932	745	596	477	14	11	9	7
Additional Profit tax ESTIMATE	20,00%	$m	0	0	0	0	0	0	153	-64	-300	-318	-372	-367	-364	-291	-233	-186	-149	-119	-95	-3	-2	-2	-1
Net contractor cashflow		$m	0	0	0	0	-54	-672	-611	255	1202	1273	1486	1469	1456	1165	932	745	596	477	382	11	9	7	6
Tullow working interest		%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Net Tullow cashflow		**$m**	**0**	**0**	**0**	**0**	**-27**	**-336**	**-305**	**128**	**600**	**636**	**742**	**734**	**727**	**582**	**465**	**372**	**298**	**238**	**191**	**6**	**5**	**4**	**3**

VALUE	PV of EV FCF	
Gross field	4875	$m
TLW	2435	$m
EV / 2P remaining working interest	17,3	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	280	mboe
Remaining gross reserves	281	mboe
Remaining reserves working interest	140	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Revenue post royalty		$m	0	0	0	0	0	0	0	1324	3021	3032	3032	3032	3032	2426	1941	1553	1242	994	795	0	0	0	0
Less costs		$m	0	0	0	0	0	0	0	-140	-336	-336	-336	-336	-336	-269	-215	-172	-138	-110	-88	0	0	0	0
Less depreciation		$m	0	0	0	0	-6	-80	-218	-314	-344	-340	-300	-240	-192	-153	-123	-98	-79	-63	-50	-40	-32	-26	-21
Taxable base		$m	0	0	0	0	-6	-80	-218	869	2341	2357	2397	2457	2505	2004	1603	1282	1026	821	657	-40	-32	-26	-21
Tax rate	35%	%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax		**$m**	**0**	**0**	**0**	**0**	**-2**	**-28**	**-76**	**304**	**820**	**825**	**839**	**860**	**877**	**701**	**561**	**449**	**359**	**287**	**230**	**-14**	**-11**	**-9**	**-7**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Starting NBV of capitalized capex	2800	$m	0	0	0	0	0	50	670	1292	1538	1558	1498	1199	959	767	614	491	393	314	251	201	161	129	103
Capex added	2800	$m	0	0	0	0	56	700	840	560	364	280	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	-6	-80	-218	-314	-344	-340	-300	-240	-192	-153	-123	-98	-79	-63	-50	-40	-32	-26	-21
Closing NBV		$m	0	0	0	0	50	670	1292	1538	1558	1498	1199	959	767	614	491	393	314	251	201	161	129	103	82
Capex phasing	TLW guidance	100%					2%	25%	30%	20%	13%	10%													
Capex	10	$/boe																							
Abandonment costs	1,0																								
Capex check																									

Tullow Equity		50%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Net Production		**kboe/d**	0	0	0	0	0	0	0	19	46	46	46	46	46	37	29	24	19	15	12	0	0	0	0
Net revenues		$m	0	0	0	0	0	0	0	696	1589	1594	1594	1594	1594	1276	1020	816	653	522	418	0	0	0	0
Net opex		$m	0	0	0	0	0	0	0	-70	-168	-168	-168	-168	-168	-134	-107	-86	-69	-55	-44	0	0	0	0
Net capex		$m	0	0	0	0	-27,97	-349,7	-419,6	-279,7	-181,8	-139,9	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	-218,6	-638,8	-650,7	-684,3	-692,7	-699,4	-559,5	-447,6	-358,1	-286,5	-229,2	-183,3	0	0	0	0
Net cash		$m	0	0	0	0	-28	-350	-420	128	600	636	742	734	727	582	465	372	298	238	191	0	0	0	0

Appendix 37 - DCF Ghana – 2015 –

Ghana 2015 - Offshore
Tullow WI 100%
Royalty 5%

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E
Field production profile	1000	99%			0,0%	0,0%	0,0%	0,0%	0,0%	7,0%	13,0%	13,0%	13,0%	6,0%	4,5%	4,0%	3,8%	3,6%
Field production		kboe/d	0	0	0,0	0,0	0,0	0,0	0,0	191,8	356,2	356,2	356,2	164,4	123,3	109,6	104,1	98,6
Production growth											86%	0%	0%	-54%	-25%	-11%	-5%	-5%
Cumulative production		mboe	0	0	0	0	0	0	0	70	200	330	460	520	565	605	643	679
Pricing assumption			**2008A**	**2009A**	**2010A**	**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**
Oil Price (Brent)	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95
Revenue calculation			**2008A**	**2009A**	**2010A**	**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**
Gross revenue	$m		0	0	0	0	0	0	0	6966	12305	12350	12350	5700	4275	3800	3610	3420
Tullow Share			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**6966**	**12305**	**12350**	**12350**	**5700**	**4275**	**3800**	**3610**	**3420**
Gross Field FCF calculation			**2008A**	**2009A**	**2010A**	**2011A**	**2012E**	**2013E**	**2014E**	**2015E**	**2016E**	**2017E**	**2018E**	**2019E**	**2020E**	**2021E**	**2022E**	**2023E**
Gross Revenue	43707	$m	0	0	0	0	0	0	0	6966	12305	12350	12350	5700	4275	3800	3610	3420
Royalty		$m	0	0	0	0	0	0	0	-348	-615	-618	-618	-285	-214	-190	-181	-171
Post royalty revenues		$m	0	0	0	0	0	0	0	6618	11690	11733	11733	5415	4061	3610	3430	3249
Production costs	-9850	$m	0	0	0	0	0	0	0	-700	-1300	-1300	-1300	-600	-450	-400	-380	-360
Capex		$m	0	0	0	0	0	-1104	-2209	-3313	-2209	-2209	0	0	0	0	0	0
Pre tax cashflows		$m	0	0	0	0	0	-1104	-2209	2605	8181	8224	10433	4815	3611	3210	3050	2889
Tax		$m	0	0	0	0	0	39	147	-1760	-3195	-3143	-3168	-1298	-954	-876	-869	-853
Net field cashflows before APT		$m	0	0	0	0	0	-1066	-2062	844	4987	5080	7265	3517	2657	2334	2180	2036
Additional Profit tax ESTIMA	25,00%	$m	0	0	0	0	0	0	0	0	-1247	-1270	-1816	-879	-664	-584	-545	-509
Net contractor cashflow		$m	0	0	0	0	0	-1066	-2062	844	3740	3810	5449	2638	1993	1751	1635	1527
Tullow working interest		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow		**$m**	**0**	**0**	**0**	**0**	**0**	**-1066**	**-2062**	**844**	**3740**	**3810**	**5449**	**2638**	**1993**	**1751**	**1635**	**1527**

Production	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E	2039E
Field production profile	3,4%	3,0%	2,9%	2,8%	2,7%	2,6%	2,5%	2,4%	2,5%	2,3%	2,0%	1,5%	1,0%	0,5%	0,2%	0,2%
Field production	93,2	82,2	79,5	76,7	74,0	71,2	68,5	65,8	68,5	63,0	54,8	41,1	27,4	13,7	5,5	5,5
Production growth	-6%	-12%	-3%	-3%	-4%	-4%	-4%	-4%	4%	-8%	-13%	-25%	-33%	-50%	-60%	0%
Cumulative production	713	743	772	800	827	853	878	902	927	950	970	985	995	1000	1002	1004
Pricing assumption	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**	**2039E**
Oil Price (Brent)	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Revenue calculation	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**	**2039E**
Gross revenue	3230	2850	2755	2660	2565	2470	2375	2280	2375	2185	1900	1425	950	475	190	190
Tullow Share	**3230**	**2850**	**2755**	**2660**	**2565**	**2470**	**2375**	**2280**	**2375**	**2185**	**1900**	**1425**	**950**	**475**	**190**	**190**
Gross Field FCF calculation	**2024E**	**2025E**	**2026E**	**2027E**	**2028E**	**2029E**	**2030E**	**2031E**	**2032E**	**2033E**	**2034E**	**2035E**	**2036E**	**2037E**	**2038E**	**2039E**
Gross Revenue	3230	2850	2755	2660	2565	2470	2375	2280	2375	2185	1900	1425	950	475	190	190
Royalty	-162	-143	-138	-133	-128	-124	-119	-114	-119	-109	-95	-71	-48	-24	-10	-10
Post royalty revenues	3069	2708	2617	2527	2437	2347	2256	2166	2256	2076	1805	1354	903	451	181	181
Production costs	-340	-300	-290	-280	-270	-260	-250	-240	-250	-230	-200	-150	-100	-50	-20	-20
Capex	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows	2729	2408	2327	2247	2167	2087	2006	1926	2006	1846	1605	1204	803	401	161	161
Tax	-828	-741	-733	-722	-706	-689	-669	-648	-681	-629	-548	-410	-272	-133	-51	-52
Net field cashflows before APT	1900	1666	1594	1525	1460	1398	1337	1278	1325	1217	1057	793	530	268	110	109
Additional Profit tax ESTIMA	-475	-417	-398	-381	-365	-349	-334	-320	-331	-304	-264	-198	-133	-67	-27	-27
Net contractor cashflow	1425	1250	1195	1144	1095	1048	1003	959	994	913	793	595	398	201	82	82
Tullow working interest	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow	**1425**	**1250**	**1195**	**1144**	**1095**	**1048**	**1003**	**959**	**994**	**913**	**793**	**595**	**398**	**201**	**82**	**82**

VALUE	PV of EV FCF	
Gross field	14045	$m
TLW	14045	$m
EV / 2P remaining w orking i	14,0	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	1004	mboe
Remaining gross reserves	1004	mboe
Remaining reserves w orkin	1004	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E	2039E
Revenue post royalty		$m	0	0	0	0	0	0	0	6618	11690	11733	11733	5415	4061	3610	3430	3249	3069	2708	2617	2527	2437	2347	2256	2166	2256	2076	1805	1354	903	451	181	181
Less costs		$m	0	0	0	0	0	0	0	-700	-1300	-1300	-1300	-600	-450	-400	-380	-360	-340	-300	-290	-280	-270	-260	-250	-240	-250	-230	-200	-150	-100	-50	-20	-20
Less depreciation		$m	0	0	0	0	0	-110	-420	-888	-1263	-1452	-1382	-1106	-885	-708	-566	-453	-362	-290	-232	-186	-148	-119	-95	-76	-61	-49	-39	-31	-25	-20	-16	-13
Taxable base		$m	0	0	0	0	0	-110	-420	5030	9128	8981	9050	3709	2727	2502	2483	2436	2366	2118	2095	2061	2018	1968	1911	1850	1945	1797	1566	1173	778	381	145	148
Tax rate	35%	%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**-39**	**-147**	**1760**	**3195**	**3143**	**3168**	**1298**	**954**	**876**	**869**	**853**	**828**	**741**	**733**	**722**	**706**	**689**	**669**	**648**	**681**	**629**	**548**	**410**	**272**	**133**	**51**	**52**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E	2039E
Starting NBV of capitalized	11044	$m	0	0	0	0	0	0	994	2783	5208	6155	6912	5529	4423	3539	2831	2265	1812	1449	1160	928	742	594	475	380	304	243	195	156	125	100	80	64
Capex added	11044	$m	0	0	0	0	0	1104	2209	3313	2209	2209	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	0	-110	-420	-888	-1263	-1452	-1382	-1106	-885	-708	-566	-453	-362	-290	-232	-186	-148	-119	-95	-76	-61	-49	-39	-31	-25	-20	-16	-13
Closing NBV		$m	0	0	0	0	0	994	2783	5208	6155	6912	5529	4423	3539	2831	2265	1812	1449	1160	928	742	594	475	380	304	243	195	156	125	100	80	64	51
Capex phasing	W guidance	100%						10%	20%	30%	20%	20%																						
Capex	11	$/boe																																
Abandonment costs	1,0																																	
Capex check																																		

Tullow Equity		100%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E	2039E
Net Production		**kboe/d**	0	0	0	0	0	0	0	192	356	356	356	164	123	110	104	99	93	82	79	77	74	71	68	66	68	63	55	41	27	14	5	5
Net revenues		$m	0	0	0	0	0	0	0	6966	12305	12350	12350	5700	4275	3800	3610	3420	3230	2850	2755	2660	2565	2470	2375	2280	2375	2185	1900	1425	950	475	190	190
Net opex		$m	0	0	0	0	0	0	0	-700	-1300	-1300	-1300	-600	-450	-400	-380	-360	-340	-300	-290	-280	-270	-260	-250	-240	-250	-230	-200	-150	-100	-50	-20	-20
Net capex		$m	0	0	0	0	0	-1104	-2209	-3313	-2209	-2209	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	-2109	-5057	-5031	-5601	-2462	-1832	-1649	-1595	-1533	-1465	-1300	-1270	-1236	-1200	-1162	-1122	-1081	-1131	-1042	-907,3	-680	-452,2	-224,2	-87,57	-88,41
Net cash		$m	0	0	0	0	0	-1104	-2209	844	3740	3810	5449	2638	1993	1751	1635	1527	1425	1250	1195	1144	1095	1048	1003	959	994	913	793	595	398	201	82	82

Appendix 38 - DCF UK fields

UK North Sea gas fields (CMS & TH)	
Southern Gas basin	
Tullow WI	**100%**
Concession: No Royalty	**No PRT**
Entitlement Factor	**100%**

Gross FCF calculation			2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E
Gross Revenue		**$m**	**356**	**531**	**151**	**178**	**246**	**259**	**280**	**281**	**279**	**268**	**258**	**248**	**33**	**19**	**0**
Production costs		$m	-141	-119	-86	-78	-89	-94	-94	-94	-94	-94	-94	-94	-13	-8	0
Capex	593	$m	-180	-116	-70	-57	-100	-70	0	0	0	0	0	0	0	0	0
Pre tax cashflow		$m	34	295	-5	43	58	96	187	188	185	174	164	155	20	11	0
Tax		$m	-21	-183	3	-27	-36	-60	-116	-117	-115	-108	-102	-96	-12	-7	0
FCF to EV			**13**	**112**	**-2**	**16**	**22**	**36**	**71**	**71**	**70**	**66**	**62**	**59**	**8**	**4**	**0**

Valuation and reserves		
Remaining NPV- gross	318	$m
Remaining NPV- net	**318**	$m
EV / 2P remaining entitled	**10**	$m
Discount rate	9%	%
Initial reserves- gross	63	mboe
Remaining reserves- gross	**32**	mboe
Remaining reserves- net	**32**	mboe

Assumptions		2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E
Gas price	$/mscf	6,8	12,0	4,7	6,2	9,0	9,7	10,5	10,5	10,4	10,0	9,6	9,3	8,9	8,6	8,5
Field production	mscf/d	144	121	87	79	75	73	73	73	73	73	73	73	10	6	0
Cumulative production	bcf	144	188	219	248	276	302	329	356	383	409	436	463	466	468	468
Variable production costs	$/mscf	2,7	2,7	2,7	2,7	3,2	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5	3,5
Cost inflation	%	0%	0%	0%	0%	20%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax rate	%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%	62%
Pre tax CF margin	%	10%	56%	-3%	24%	23%	37%	67%	67%	0%	0%	0%	0%	0%	0%	0%
Net CF margin	%	4%	21%	-1%	9%	9%	14%	25%	25%	0%	0%	0%	0%	0%	0%	0%
Tullow WI gas production	mscf/d	144	121	87	79	75	73	73	73	73	73	73	73	10	6	0
WI production	kb/d	24	20	15	13	12,5	12,2	12,2	12,2	12,2	12	12	12	2	1	0

Tullow Equity	100%	2007A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E
Net Production	**kboe/d**	24	20	15	13	13	12	12	12	12	12	12	12	2	1	0
Net revenues	$m	356	531	151	178	246	259	280	281	279	268	258	248	33	19	0
Net opex	$m	-141	-119	-86	-78	-89	-94	-94	-94	-94	-94	-94	-94	-13	-8	0
Net capex	$m	-180	-116	-70	-57	-100	-70	0	0	0	0	0	0	0	0	0
Net Tax	$m	-21	-183	3	-27	-36	-60	-116	-117	-115	-108	-102	-96	-12	-7	0
Net cash	$m	13	112	-2	16	22	36	71	71	70	66	62	59	8	4	0

Appendix 39 - DCF The Netherlands

NETHERLANDS- Nuon
Tullow WI 15%

PROFIT OIL			2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Gross revenue (before royalty)	10630	$m	**0**	**394**	**964**	**1699**	**2048**	**1690**	**1516**	**938**	**452**	**193**	**185**	**184**	**184**	**184**	**0**	**0**
Actual costs inc. capex	-5315	$m	0	-165	-714	-894	-963	-844	-804	-356	-178	-79	-79	-79	-79	-79	0	0
Income tax		$m	0	-131	-265	-487	-578	-458	-391	-236	-112	-57	-53	-53	-52	-52	0	0
CIT		$m	0	-33	-68	-124	-147	-117	-100	-60	-28	-14	-13	-13	-13	-13	0	0
Net contractor cashflow		$m	**0**	**65**	**-83**	**193**	**360**	**271**	**221**	**286**	**133**	**42**	**39**	**39**	**39**	**39**	**0**	**0**
Equity		%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Net cashflow	-50%	$m	**0**	**10**	**-12**	**29**	**54**	**41**	**33**	**43**	**20**	**6**	**6**	**6**	**6**	**6**	**0**	**0**

VALUATION	PV OF EV FCF	
Remaining NPV - gross	985	$m
Remaining net NPV	148	$m
EV / 2P remaining WI	5,5	$/ boe WI
EV / 2P remaining entitled	5,5	$ / boe ent
Discount rate	10%	
Reserves data- on 2P basis		
Initial reserves- gross	180	mboe
Gross remaining reserves	178	mboe
Working interest reserves	27	mboe
Net entitled reserves	27	mboe
Working interest	15%	%
Remaining entitlement factor	100%	%

REVENUE			2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Gross Revenue		$m	**0**	**394**	**964**	**1699**	**2048**	**1690**	**1516**	**938**	**452**	**193**	**185**	**184**	**184**	**184**	**0**	**0**
European gas price		$/Mcf	6	9	10	10	11	10	10	10	9	9	9	9	9	8	8	8

PRODUCTION			2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Production profile- % of initial reserves	180	mboe (%)	**0%**	**4%**	**9%**	**15%**	**18%**	**15%**	**14%**	**9%**	**5%**	**2%**	**2%**	**2%**	**2%**	**2%**	**0%**	0,0%
Field production GROSS	98,7%	**Mscf/d**	**0**	**120**	**272**	**444**	**533**	**444**	**414**	**266**	**133**	**59**	**59**	**59**	**59**	**59**	**0**	**0**
Cumulative production		mboe	0	44	143	305	499	661	813	910	958	980	1002	1023	1045	1066	1066	1066
Field production **GROSS**		**kboe/d**	0,0	20,0	45,3	74,0	88,8	74,0	69,0	44,4	22,2	9,9	9,9	9,9	9,9	9,9	0,0	0,0
WI Production Approximately **NET**		**kboe/d**	0,0	3,0	6,8	11,1	13,3	11,1	10,4	6,7	3,3	1,5	1,5	1,5	1,5	1,5	0,0	0,0
Cost inflation			10%	5%	5%	3%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

ACTUAL COSTS			2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Variable production costs/bbl		$/bbl	0,0	17,1	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0	22,0
Production costs	3875	$m	0	125	364	594	713	594	554	356	178	79	79	79	79	79	0	0
Capex	1440	$m	0	40	350	300	250	250	250	0	0	0	0	0	0	0	0	0
Total costs		**$m**	**0**	**165**	**714**	**894**	**963**	**844**	**804**	**356**	**178**	**79**	**79**	**79**	**79**	**79**	**0**	**0**

TAX			2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
PPT			0	261	530	975	1155	916	781	471	223	114	106	105	105	104	0	0
Tax rate	50,0%		-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%	-50%
PPT Tax			**0**	**-131**	**-265**	**-487**	**-578**	**-458**	**-391**	**-236**	**-112**	**-57**	**-53**	**-53**	**-52**	**-52**	**0**	**0**
CIT tax base			0	131	265	487	578	458	391	236	112	57	53	53	52	52	0	0
CIT tax	25,5%		**0**	**-33**	**-68**	**-124**	**-147**	**-117**	**-100**	**-60**	**-28**	**-14**	**-13**	**-13**	**-13**	**-13**	**0**	**0**
Starting capex		$m	0	0	32	312	482	552	622	692	582	532	532	532	532	532	532	532
Capex yr 1		$m	0	40	350	300	250	250	250	0	0	0	0	0	0	0	0	0
Depreciation	-20,0%	$m	0	-8	-70	-130	-180	-180	-180	-110	-50	0	0	0	0	0	0	0
Closing book value		$m	0	32	312	482	552	622	692	582	532	532	532	532	532	532	532	532

Net tullow	15%	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E
Net Production	**kboe/d**	0	3	7	11	13	11	10	7	3	1	1	1	1	1	0	0
Net revenues	$m	0	59	145	255	307	253	227	141	68	29	28	28	28	28	0	0
Net opex	$m	0	-19	-55	-89	-107	-89	-83	-53	-27	-12	-12	-12	-12	-12	0	0
Net capex	$m	0	-6	-52,5	-45	-37,5	-37,5	-37,5	0	0	0	0	0	0	0	0	0
Net Tax	$m	0	-25	-50	-92	-109	-86	-74	-44	-21	-11	-10	-10	-10	-10	0	0
Net cash	$m	0	10	-12	29	54	41	33	43	20	6	6	6	6	6	0	0

Appendix 40 - DCF Uganda

UGANDA	Offshore
Tullow	33%
Royalty	PSC

PSC - Oil Production

	Production	Contractor share
kboe/d	5	55%
kboe/d	10	50%
kboe/d	20	45%
kboe/d	30	40%
kboe/d	40	35%
kboe/d	> 40	33%

Source: Company Data Uganda, NAV Model

PSC - Royalty rate based on daily prod.

	Production	Royalty
kboe/d	2,5	5,0%
kboe/d	5	7,5%
kboe/d	7,5	10,0%
kboe/d	> 7,5	12,5%

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Field production profile	1100	100%			0,0%	0,0%	0,0%	0,7%	3,3%	5,5%	6,5%	7,0%	7,3%	7,4%	7,5%	7,4%	7,1%
Field production		kboe/d	0	0	0	0	0	20	100	165	195	210	220	223	225	223	215
Production growth											18%	8%	5%	1%	1%	-1%	-3%
Cumulative production		mboe	0	0	0	0	0	7	44	104	175	252	332	414	496	577	655

Production	Total		2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Field production profile	1100	100%	6,8%	6,3%	5,6%	5,0%	4,3%	3,3%	2,7%	2,5%	2,0%	1,5%	0,0%	0,0%	0,0%	0,0%	0,0%	0,0%
Field production		kboe/d	205	190	170	150	130	100	80	75	60	45	0	0	0	0	0	0
Production growth			-5%	-7%	-11%	-12%	-13%	-23%	-20%	-6%								
Cumulative production		mboe	730	800	862	917	964	1001	1030	1057	1079	1096	1096	1096	1096	1096	1096	1096

Pricing assumption		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Oil Price (Brent)	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95

Pricing assumption		2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Oil Price (Brent)	$/bbl	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Profit Oil calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Gross revenue (before royalty)		$m	0	0	0	0	0	826	3867	5996	6740	7285	7632	7719	7806	7719	7459
Royalty rate PSA		%	5,0%	5,0%	5,0%	5,0%	5,0%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%
Royalty		$m	0	0	0	0	0	-103	-483	-750	-843	-911	-954	-965	-976	-965	-932
Recovered costs inc. capex	20%	$m	0	0	0	0	0	0	0	-1199	-1348	-1457	-1526	-1544	-1561	-1544	-1492
Profit oil available		$m	0	0	0	0	0	826	3867	4047	4550	4918	5152	5210	5269	5210	5035
Profit share (contractor)		%	55%	55%	55%	55%	55%	40%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Total profit oil for contractors		$m	**0**	**0**	**0**	**0**	**0**	**331**	**1257**	**1315**	**1479**	**1598**	**1674**	**1693**	**1712**	**1693**	**1636**

Profit Oil calculation			2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Gross revenue (before royalty)		$m	7112	6591	5898	5204	4510	3469	2775	2613	2090	1568	0	0	0	0	0	0
Royalty rate PSA		%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	12,5%	5,0%	5,0%	5,0%	5,0%	5,0%	5,0%
Royalty		$m	-889	-824	-737	-650	-564	-434	-347	-327	-261	-196	0	0	0	0	0	0
Recovered costs inc. capex	20%	$m	-1422	-1318	-1180	-1041	-902	-694	-555	-523	-418	-314	0	0	0	0	0	0
Profit oil available		$m	4800	4449	3981	3513	3044	2342	1873	1763	1411	1058	0	0	0	0	0	0
Profit share (contractor)		%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	55%	55%	55%	55%	55%	55%
Total profit oil for contractors		$m	**1560**	**1446**	**1294**	**1142**	**989**	**761**	**609**	**573**	**458**	**344**	**0**	**0**	**0**	**0**	**0**	**0**

Contractor take of cashflows		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E
Contractor revenues	$m	0	0	0	0	0	331	1257	2515	2827	3055	3201	3237	3273	3237	3128
Actual costs inc. capex	$m	0	0	0	0	-330	-1188	-2088	-2098	-1405	-1195	-1074	-1085	-986	-975	-942
Income tax	$m	0	0	0	0	10	9	23	-348	-383	-448	-506	-540	-572	-587	-583
Net contractor cashflow	$m	**0**	**0**	**0**	**0**	**-320**	**-848**	**-809**	**68**	**1040**	**1412**	**1621**	**1612**	**1716**	**1675**	**1603**
Tullow equity	%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Net Tullow cashflow	$m	**0**	**0**	**0**	**0**	**-107**	**-283**	**-270**	**23**	**347**	**471**	**540**	**537**	**572**	**558**	**534**

Contractor take of cashflows		2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Contractor revenues	$m	2982	2764	2473	2182	1891	1455	1164	1096	876	657	0	0	0	0	0	0
Actual costs inc. capex	$m	-898	-833	-745	-657	-570	-438	-351	-330	-264	-198	0	0	0	0	0	0
Income tax	$m	-567	-533	-481	-428	-373	-286	-229	-217	-174	-130	6	5	4	3	3	2
Net contractor cashflow	$m	**1517**	**1399**	**1247**	**1097**	**949**	**731**	**585**	**548**	**439**	**329**	**6**	**5**	**4**	**3**	**3**	**2**
Tullow equity	%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Net Tullow cashflow	$m	**506**	**466**	**416**	**366**	**316**	**244**	**195**	**183**	**146**	**110**	**2**	**2**	**1**	**1**	**1**	**1**

VALUE	PV of EV FCF	
Gross field	6292	$m
TLW	2097	$m
EV / 2P remaining working interest	5,7	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	1100	mboe
Remaining gross reserves	1096	mboe
Remaining reserves working interest	365	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Revenue post royalty		$m	0	0	0	0	0	723	3383	5247	5898	6375	6678	6754	6830	6754	6526	6223	5767	5160	4553	3946	3035	2428	2286	1829	1372	0	0	0	0	0	0
Less costs		$m	0	0	0	0	0	-88	-438	-723	-855	-920	-964	-975	-986	-975	-942	-898	-833	-745	-657	-570	-438	-351	-330	-264	-198	0	0	0	0	0	0
Less depreciation		$m	0	0	0	0	-33	-169	-411	-631	-697	-640	-551	-463	-381	-305	-244	-195	-156	-125	-100	-80	-64	-51	-41	-33	-26	-21	-17	-13	-11	-9	-7
Ugandan Gvmt share		$m		0	0	0	0	-496	-2610	-2732	-3071	-3319	-3477	-3517	-3556	-3517	-3398	-3240	-3003	-2687	-2371	-2055	-1581	-1265	-1190	-952	-714	0	0	0	0	0	0
Taxable base		$m	0	0	0	0	-33	-30	-75	1161	1275	1495	1686	1799	1906	1957	1942	1889	1776	1603	1425	1242	953	762	725	580	433	-21	-17	-13	-11	-9	-7
Tax rate	30%	%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
Tax		**$m**	**0**	**0**	**0**	**0**	**10**	**9**	**23**	**-348**	**-383**	**-448**	**-506**	**-540**	**-572**	**-587**	**-583**	**-567**	**-533**	**-481**	**-428**	**-373**	**-286**	**-229**	**-217**	**-174**	**-130**	**6**	**5**	**4**	**3**	**3**	**2**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized capex	5500	$m	0	0	0	0	0	297	1228	2467	3211	3064	2699	2258	1905	1524	1219	976	780	624	499	400	320	256	205	164	131	105	84	67	54	43	34
Capex added	5500	$m	0	0	0	0	330	1100	1650	1375	550	275	110	110	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	-33	-169	-411	-631	-697	-640	-551	-463	-381	-305	-244	-195	-156	-125	-100	-80	-64	-51	-41	-33	-26	-21	-17	-13	-11	-9	-7
Closing NBV		$m	0	0	0	0	297	1228	2467	3211	3064	2699	2258	1905	1524	1219	976	780	624	499	400	320	256	205	164	131	105	84	67	54	43	34	27
Capex phasing	W guidance	98%			0%	0%	6%	20%	30%	25%	10%	5%	2%	2%	0%	0%	0%																
Capex	5	$/boe																															
Abandonment costs	1,0																																
Capex check																																	

Actual Costs			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Variable production costs/bbl		$/bbl	0,0	9,0	9,9	10,4	11,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0	12,0
Production costs		$m	0	0	0	0	0	88	438	723	855	920	964	975	986	975	942	898	833	745	657	570	438	351	330	264	198	0	0	0	0	0	0
Capex Including Exploration	5500	$m	0	0	0	0	330	1100	1650	1375	550	275	110	110	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exploration		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs																																	
Total costs		**$m**	**0**	**0**	**0**	**0**	**330**	**1188**	**2088**	**2098**	**1405**	**1195**	**1074**	**1085**	**986**	**975**	**942**	**898**	**833**	**745**	**657**	**570**	**438**	**351**	**330**	**264**	**198**	**0**	**0**	**0**	**0**	**0**	**0**

Tullow Equity		33%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Net Production		kboe/d	0	0	0	0	0	7	33	55	65	70	73	74	75	74	72	68	63	57	50	43	33	27	25	20	15	0	0	0	0	0	0
Net revenues		$m	0	0	0	0	0	145	580	1088	1223	1322	1385	1401	1416	1401	1353	1290	1196	1070	944	818	630	504	474	379	284	0	0	0	0	0	0
Net opex		$m	0	0	0	0	0	-29	-146	-241	-285	-307	-321	-325	-329	-325	-314	-299	-278	-248	-219	-190	-146	-117	-110	-88	-66	0	0	0	0	0	0
Net capex		$m	0	0	0	0	-110	-366,67	-550	-458,33	-183,33	-91,667	-36,667	-36,667	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	-31,44	-153,57	-365,91	-408,35	-453,02	-486,6	-501,57	-515,87	-517,34	-504,97	-485,23	-452,2	-406,08	-359,33	-312,09	-239,82	-191,86	-181,32	-145,06	-108,63	0	0	0	0	0	0
Net cash		$m	0	0	0	0	-110	-283	-270	23	347	471	540	537	572	558	534	506	466	416	366	316	244	195	183	146	110	0	0	0	0	0	0

Appendix 41 - DCF Namibia

Namibia Kudu	**Offshore, Orange basin**	
Tullow WI	**31%**	
Royalty	**13%**	

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Field production profile	500	mboe			0,0%	0,0%	0,0%	0,0%	0,0%	2,5%	3,0%	5,0%	7,0%	8,0%	8,0%	8,0%	8,0%	8,0%	7,0%	6,0%	5,0%	4,0%	3,0%	3,0%	2,5%	2,5%	2,5%	2,0%	2,0%	2,0%
Field production	3000	mmscf/d	0	0	0	0	0	0	0	205	247	411	575	658	658	658	658	658	575	493	411	329	247	247	205	205	205	164	164	164
Field production equivalent		kboe/d	0	0	0	0	0	0	0	34	41	68	96	110	110	110	110	110	96	82	68	55	41	41	34	34	34	27	27	27
Cumulative production		mboe	0	0	0	0	0	0	0	13	28	53	88	128	168	208	248	288	323	353	378	398	413	428	440	453	465	475	485	495

Pricing assumption			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Gas price assumption		$/mscf	12	5	6	9	10	10	11	10	10	10	9	9	9	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8
Discount	5%	%	0,6	0,2	0,3	0,4	0,5	0,5	0,5	0,5	0,5	0,5	0,5	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4	0,4
Realised gas price		$/mscf	11	5	6	9	9	10	10	10	10	9	9	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8

Gross Field FCF calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Gross Revenue	24533	$m	0	0	0	0	0	0	0	743	857	1375	1854	2036	1950	1947	1942	1938	1692	1447	1203	960	717	714	592	590	587	466	463	459
Royalty		$m	0	0	0	0	0	0	0	-93	-107	-172	-232	-254	-244	-243	-243	-242	-211	-181	-150	-120	-90	-89	-74	-74	-73	-58	-58	-57
Post royalty revenues		$m	0	0	0	0	0	0	0	650	750	1203	1622	1781	1706	1704	1700	1696	1480	1266	1053	840	627	625	518	516	514	408	405	402
Production costs	-4950	$m	0	0	0	0	0	0	0	-125	-150	-250	-350	-400	-400	-400	-400	-400	-350	-300	-250	-200	-150	-150	-125	-125	-125	-100	-100	-100
Capex		$m	0	0	0	0	0	-375	-750	-300	-75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	0	0	0	0	0	-375	-750	225	525	953	1272	1381	1306	1304	1300	1296	1130	966	803	640	477	475	393	391	389	308	305	302
Tax		$m	0	0	0	0	0	13	50	-107	-136	-271	-395	-444	-425	-431	-434	-437	-383	-328	-273	-217	-162	-162	-134	-134	-134	-106	-105	-105
Net field cashflows before APT		$m	0	0	0	0	0	-362	-700	118	389	682	876	938	881	873	865	859	748	638	530	423	316	313	259	257	255	202	200	197
Additional Profit tax ESTIMATE	30,00%	$m	0	0	0	0	0	0	0	-35	-117	-204	-263	-281	-264	-262	-260	-258	-224	-192	-159	-127	-95	-94	-78	-77	-76	-61	-60	-59
Net contractor cashflow		$m	0	0	0	0	0	-362	-700	83	273	477	614	656	617	611	606	601	523	447	371	296	221	219	181	180	178	141	140	138
Tullow working interest		%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%	31%
Net Tullow cashflow		**$m**	**0**	**0**	**0**	**0**	**0**	**-112**	**-217**	**26**	**85**	**148**	**190**	**203**	**191**	**189**	**188**	**186**	**162**	**139**	**115**	**92**	**69**	**68**	**56**	**56**	**55**	**44**	**43**	**43**

VALUE	PV of EV FCF	
Gross field	2286	$m
TLW	709	$m
EV / 2P remaining w orking interest	4,6	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	500	mboe
Remaining gross reserves	495	mboe
Remaining reserves w orking interest	153	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Revenue post royalty		$m	0	0	0	0	0	0	0	650	750	1203	1622	1781	1706	1704	1700	1696	1480	1266	1053	840	627	625	518	516	514	408	405	402
Less costs		$m	0	0	0	0	0	0	0	-125	-150	-250	-350	-400	-400	-400	-400	-400	-350	-300	-250	-200	-150	-150	-125	-125	-125	-100	-100	-100
Less depreciation		$m	0	0	0	0	0	-38	-143	-219	-213	-178	-142	-114	-91	-73	-58	-47	-37	-30	-24	-19	-15	-12	-10	-8	-6	-5	-4	-3
Taxable base		$m	0	0	0	0	0	-38	-143	306	387	775	1130	1268	1215	1231	1241	1249	1093	936	779	621	462	463	384	383	383	303	301	299
Tax rate	35%	%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%	35%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**-13**	**-50**	**107**	**136**	**271**	**395**	**444**	**425**	**431**	**434**	**437**	**383**	**328**	**273**	**217**	**162**	**162**	**134**	**134**	**134**	**106**	**105**	**105**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Starting NBV of capitalized capex	1500	$m	0	0	0	0	0	0	338	945	1026	888	711	569	455	364	291	233	186	149	119	95	76	61	49	39	31	25	20	16
Capex added	1500	$m	0	0	0	0	0	375	750	300	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	0	-38	-143	-219	-213	-178	-142	-114	-91	-73	-58	-47	-37	-30	-24	-19	-15	-12	-10	-8	-6	-5	-4	-3
Closing NBV		$m	0	0	0	0	0	338	945	1026	888	711	569	455	364	291	233	186	149	119	95	76	61	49	39	31	25	20	16	13
Capex phasing	W guidance	100%						25%	50%	20%	5%																			
Capex	3	$/boe																												
Abandonment costs	1,0																													
Capex check																														

Tullow Equity		0A	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E
Net Production		kboe/d	0	0	0	0	0	0	0	11	13	21	30	34	34	34	34	34	30	25	21	17	13	13	11	11	11	8	8	8
Net revenues		$m	0	0	0	0	0	0	0	230	266	426	575	631	605	604	602	601	525	449	373	298	222	221	184	183	182	145	143	142
Net opex		$m	0	0	0	0	0	0	0	-39	-47	-78	-109	-124	-124	-124	-124	-124	-109	-93	-78	-62	-47	-47	-39	-39	-39	-31	-31	-31
Net capex		$m	0	0	0	0	0	-116,25	-232,5	-93	-23,25	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	-73,026	-111,46	-200,77	-275,91	-303,61	-289,35	-290,15	-290,39	-290,47	-253,72	-217,03	-180,43	-143,94	-107,3	-106,95	-88,671	-88,335	-87,968	-69,716	-69,133	-68,535
Net cash		$m	0	0	0	0	0	-116	-233	26	85	148	190	203	191	189	188	186	162	139	115	92	69	68	56	56	55	44	43	43

Appendix 42 - DCF French Guiana

French Guiana	**Offshore**
Tullow	**100%**
Royalty	**13%**

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Field production profile	175	103%	0%	0%	0%	0%	0%	0%	0%	0,0%	0,0%	0,0%	7,5%	12,0%	12,0%	12,0%	12,0%	12,0%	9,6%	7,7%	6,1%	4,9%	3,9%	3,1%	0,0%
Field production		kboe/d	0	0	0	0	0	0	0	0	0	0	36	58	58	58	58	58	46	37	29	24	19	15	0
Production growth														60%	0%	0%	0%	0%	-20%	-20%	-20%	-20%	-20%	-20%	-100%
Cumulative production		mboe	0	0	0	0	0	0	0	0	0	0	13	34	55	76	97	118	135	148	159	168	175	180	180

Pricing assumption			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Oil Price (Brent)	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Revenue calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross revenue	$m		0	0	0	0	0	0	0	0	0	0	1247	1995	1995	1995	1995	1995	1596	1277	1021	817	654	523	0
Tullow Share			**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**1247**	**1995**	**1995**	**1995**	**1995**	**1995**	**1596**	**1277**	**1021**	**817**	**654**	**523**	**0**

Gross Field FCF calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Gross Revenue	17110	$m	0	0	0	0	0	0	0	0	0	0	1247	1995	1995	1995	1995	1995	1596	1277	1021	817	654	523	0
Royalty		$m	0	0	0	0	0	0	0	0	0	0	-156	-249	-249	-249	-249	-249	-200	-160	-128	-102	-82	-65	0
Post royalty revenues		$m	0	0	0	0	0	0	0	0	0	0	1091	1746	1746	1746	1746	1746	1397	1117	894	715	572	458	0
Production costs	-1622	$m	0	0	0	0	0	0	0	0	0	0	-118	-189	-189	-189	-189	-189	-151	-121	-97	-77	-62	-50	0
Capex		$m	0	0	0	0	0	0	0	0	0	-315	-735	-840	-210	0	0	0	0	0	0	0	0	0	0
Pre tax cashflows		$m	0	0	0	0	0	0	0	0	0	-315	238	716	1346	1556	1556	1556	1245	996	797	638	510	408	0
Tax		$m	0	0	0	0	0	0	0	0	0	25	-310	-492	-502	-526	-545	-561	-448	-359	-287	-230	-184	-147	0
Net contractor cashflow		$m	0	0	0	0	0	0	0	0	0	-290	-72	224	845	1031	1011	996	797	637	510	408	326	261	0
Tullow working interest		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-290**	**-72**	**224**	**845**	**1031**	**1011**	**996**	**797**	**637**	**510**	**408**	**326**	**261**	**0**

VALUE	PV of EV FCF	
Gross field	2332	$m
TLW	2332	$m
EV / 2P remaining w orking int	12,9	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	175	mboe
Remaining gross reserves	180	mboe
Remaining reserves w orking	180	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Revenue post royalty		$m	0	0	0	0	0	0	0	0	0	0	1091	1746	1746	1746	1746	1746	1397	1117	894	715	572	458	0
Less costs		$m	0	0	0	0	0	0	0	0	0	0	-118	-189	-189	-189	-189	-189	-151	-121	-97	-77	-62	-50	0
Less depreciation		$m	0	0	0	0	0	0	0	0	0	-63	-197	-326	-303	-242	-194	-155	-124	-99	-79	-63	-51	-41	0
Taxable base		$m	0	0	0	0	0	0	0	0	0	-63	775	1231	1254	1314	1363	1401	1121	897	718	574	459	367	0
Tax rate	40%	%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-25**	**310**	**492**	**502**	**526**	**545**	**561**	**448**	**359**	**287**	**230**	**184**	**147**	**0**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Starting NBV of capitalized c	2100	$m	0	0	0	0	0	0	0	0	0	0	252	790	1304	1211	969	775	620	496	397	317	254	203	163
Capex added	2100	$m	0	0	0	0	0	0	0	0	0	315	735	840	210	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%	20%	$m	0	0	0	0	0	0	0	0	0	-63	-197	-326	-303	-242	-194	-155	-124	-99	-79	-63	-51	-41	0
Closing NBV		$m	0	0	0	0	0	0	0	0	0	252	790	1304	1211	969	775	620	496	397	317	254	203	163	163
Capex phasing	W guidance	50%										15%	35%	40%	10%										
Capex	12	$/boe																							
Abandonment costs	1,0																								
Capex check																									

Tullow Equity		100%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E
Net Production		**kboe/d**	0	0	0	0	0	0	0	0	0	0	36	58	58	58	58	58	46	37	29	24	19	15	0
Net revenues		$m	0	0	0	0	0	0	0	0	0	0	1247	1995	1995	1995	1995	1995	1596	1277	1021	817	654	523	0
Net opex		$m	0	0	0	0	0	0	0	0	0	0	-118	-189	-189	-189	-189	-189	-151	-121	-97	-77	-62	-50	0
Net capex		$m	0	0	0	0	0	0	0	0	0	-315	-735	-840	-210	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	0	0	0	-466	-741,6	-750,9	-775,1	-794,5	-810	-648	-518,4	-414,7	-331,8	-265,4	-212,3	0
Net cash		$m	0	0	0	0	0	0	0	0	0	-315	-72	224	845	1031	1011	996	797	637	510	408	326	261	0

Appendix 43 - DCF Guyana

Guyana	
Tullow WI	100%
Royalty	PSC

PSC - Oil Production		
	Production	Contractor share %
kboe/d	0	47,0%
kboe/d	40	50,0%

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Field production profile	175	90%			0%	0%	0%	0%	0%	0,0%	5,0%	8,0%	7,5%	6,5%	5,7%	5,3%	4,8%	4,5%	4,3%	4,0%	3,9%	3,8%	3,7%	3,6%	3,5%	3,4%	3,3%	3,2%	3,1%	3,0%	2,9%	2,5%	2,5%
Field production		kboe/d	0	0	0	0	0	0	0	0	24	38	36	31	27	25	23	22	21	19	19	18	18	17	17	16	16	15	15	14	14	12	12
Production growth												60%	-6%	-13%	-12%	-7%	-9%	-6%	-4%	-7%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-14%	0%
Cumulative production		mboe	0	0	0	0	0	0	0	0	9	23	36	47	57	67	75	83	90	97	104	111	117	124	130	136	141	147	152	158	163	167	172

Pricing assumption		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Oil Price (Brent)	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl	97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Profit Oil calculation		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Gross revenue (before royalty)	$m	0	0	0	0	0	0	0	0	828	1330	1247	1081	948	881	798	748	715	665	648	632	615	599	582	565	549	532	515	499	482	416	416
Recovered costs inc. capex	$m	0	0	0	0	0	0	0	0	-663	-998	-748	-108	-95	-88	-84	-79	-75	-70	-68	-63	-62	-30	-29	-28	-11	-11	-10	-10	-10	-8	0
Profit oil available	$m	0	0	0	0	0	0	0	0	166	333	499	973	853	793	714	670	640	595	580	569	554	569	553	537	538	521	505	489	472	407	416
Profit share (contractor)	%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%
Total profit oil for contractors	$m	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**83**	**166**	**249**	**486**	**426**	**397**	**357**	**335**	**320**	**298**	**290**	**284**	**277**	**284**	**276**	**268**	**269**	**261**	**253**	**244**	**236**	**204**	**208**

Contractor take of cashflows		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Contractor revenues	$m	0	0	0	0	0	0	0	0	745	1164	998	594	521	485	441	413	395	367	358	347	338	314	305	297	280	271	263	254	246	212	208
Actual costs inc. capex	$m	0	0	0	0	0	0	-315	-1050	-814	-126	-118	-102	-90	-84	-76	-71	-68	-63	-61	-60	-58	-57	-55	-54	-52	-50	-49	-47	-46	-39	-39
Income tax	$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net contractor cashflow	$m	**0**	**0**	**0**	**0**	**0**	**0**	**-315**	**-1050**	**-68**	**1038**	**879**	**492**	**431**	**401**	**365**	**342**	**327**	**304**	**297**	**288**	**280**	**257**	**250**	**243**	**228**	**221**	**214**	**207**	**200**	**173**	**168**
Tullow equity	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow	$m	**0**	**0**	**0**	**0**	**0**	**0**	**-315**	**-1050**	**-68**	**1038**	**879**	**492**	**431**	**401**	**365**	**342**	**327**	**304**	**297**	**288**	**280**	**257**	**250**	**243**	**228**	**221**	**214**	**207**	**200**	**173**	**168**

VALUE	PV of EV FCF	
Gross field	1727	$m
TLW	1727	$m
EV / 2P remaining working i	11,0	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	175	mboe
Remaining gross reserves	158	mboe
Remaining reserves workin	158	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Revenue		$m	0	0	0	0	0	0	0	0	828	1330	1247	1081	948	881	798	748	715	665	648	632	615	599	582	565	549	532	515	499	482	416	416
Less costs		$m	0	0	0	0	0	0	0	0	-79	-126	-118	-102	-90	-84	-76	-71	-68	-63	-61	-60	-58	-57	-55	-54	-52	-50	-49	-47	-46	-39	-39
Less depreciation		$m	0	0	0	0	0	0	-32	-162	-308	-320	-256	-205	-164	-131	-105	-84	-67	-54	-43	-34	-27	-22	-18	-14	-11	-9	-7	-6	-5	-4	-3
Gvmt share		$m		0	0	0	0	0	0	0	-83	-166	-249	-486	-426	-397	-357	-335	-320	-298	-290	-284	-277	-284	-276	-268	-269	-261	-253	-244	-236	-204	-208
Taxable base		$m	0	0	0	0	0	0	-32	-162	359	718	623	287	268	270	260	259	260	251	254	253	253	235	233	229	217	212	207	201	196	169	165
Tax rate	0%	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized	2100	$m	0	0	0	0	0	0	0	284	1172	1599	1279	1023	819	655	524	419	335	268	215	172	137	110	88	70	56	45	36	29	23	18	15
Capex added	2100	$m	0	0	0	0	0	0	315	1050	735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	0	0	-32	-162	-308	-320	-256	-205	-164	-131	-105	-84	-67	-54	-43	-34	-27	-22	-18	-14	-11	-9	-7	-6	-5	-4	-3
Closing NBV		$m	0	0	0	0	0	0	284	1172	1599	1279	1023	819	655	524	419	335	268	215	172	137	110	88	70	56	45	36	29	23	18	15	12
Capex phasing	W guidance	100%	0%	0%	0%	0%	0%	0%	15%	50%	35%	0%	0%	0%	0%	0%	0%																
Capex	12	$/boe																															
Abandonment costs	1,0																																
Capex check																																	

Actual Costs			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Variable production costs/bbl		$/bbl	0,0	7,0	7,7	8,1	8,5	8,7	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0	9,0
Production costs		$m	0	0	0	0	0	0	0	0	79	126	118	102	90	84	76	71	68	63	61	60	58	57	55	54	52	50	49	47	46	39	39
Capex Including Exploration	2100	$m	0	0	0	0	0	0	315	1050	735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exploration		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs																																	
Total costs		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**315**	**1050**	**814**	**126**	**118**	**102**	**90**	**84**	**76**	**71**	**68**	**63**	**61**	**60**	**58**	**57**	**55**	**54**	**52**	**50**	**49**	**47**	**46**	**39**	**39**

Tullow Equity		100%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Net Production		kboe/d	0	0	0	0	0	0	0	0	24	38	36	31	27	25	23	22	21	19	19	18	18	17	17	16	16	15	15	14	14	12	12
Net revenues		$m	0	0	0	0	0	0	0	0	745	1164	998	594	521	485	441	413	395	367	358	347	338	314	305	297	280	271	263	254	246	212	208
Net opex		$m	0	0	0	0	0	0	0	0	-79	-126	-118	-102	-90	-84	-76	-71	-68	-63	-61	-60	-58	-57	-55	-54	-52	-50	-49	-47	-46	-39	-39
Net capex		$m	0	0	0	0	0	0	-315	-1050	-735	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net cash		$m	0	0	0	0	0	0	-315	-1050	-68	1038	879	492	431	401	365	342	327	304	297	288	280	257	250	243	228	221	214	207	200	173	168

Appendix 44 - DCF Suriname

Suriname 2015 -	
Tullow WI	100%
Royalty	6%
PSC	15%

Production	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Field production profile	250	100%			0%	0%	0%	0%	0%	1%	5%	7%	9%	9%	9%	8%	7%	7%	6%	5%	4%	4%	3%	3%	2%	2%	2%	2%	2%	2%	2%	2%	0%
Field production		kboe/d	0	0	0	0	0	0	0	3	34	48	58	63	59	53	48	45	40	35	29	25	22	19	16	14	14	14	14	14	10	10	0
Production growth											880%	43%	21%	8%	-7%	-10%	-9%	-7%	-11%	-12%	-18%	-14%	-11%	-13%	-14%	-17%	0%	0%	0%	0%	-25%	0%	-100%
Cumulative production		mboe	0	0	0	0	0	0	0	1	14	31	52	75	97	116	134	150	164	177	188	197	205	212	218	223	228	233	238	243	246	250	250

Pricing assumption			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Oil Price (Brent)	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Discount to Brent	$/bbl		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Realised oil price	$/bbl		97	63	80	111	118	113	106	100	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95

Profit Oil calculation			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Gross revenue (before royalty)		$m	0	0	0	0	0	0	0	124	1160	1663	2019	2185	2043	1829	1663	1544	1378	1211	998	855	760	665	570	475	475	475	475	475	356	356	0
Royalty		$m	0	0	0	0	0	0	0	-8	-73	-105	-127	-138	-129	-115	-105	-97	-87	-76	-63	-54	-48	-42	-36	-30	-30	-30	-30	-30	-22	-22	0
Recovered costs inc. capex		$m	0	0	0	0	0	0	0	-100	-870	-499	-121	-131	-123	-110	-100	-93	-83	-82	-80	-68	-38	-33	-29	-10	-10	-10	-10	0	0	0	0
Profit oil available		$m	0	0	0	0	0	0	0	25	290	1164	1898	2054	1920	1719	1563	1451	1295	1129	918	787	722	632	542	466	466	466	466	475	356	356	0
Profit share (contractor)		%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Total profit oil for contractors		$m	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**4**	**43**	**175**	**285**	**308**	**288**	**258**	**234**	**218**	**194**	**169**	**138**	**118**	**108**	**95**	**81**	**70**	**70**	**70**	**70**	**71**	**53**	**53**	**0**

Contractor take of cashflows			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Contractor revenues		$m	0	0	0	0	0	0	0	103	913	673	406	439	411	368	334	310	277	251	217	186	146	128	110	79	79	79	79	71	53	53	0
Actual costs inc. capex		$m	0	0	0	0	0	0	-375	-506	-438	-90	-109	-118	-111	-99	-90	-84	-75	-66	-54	-46	-41	-36	-31	-26	-26	-26	-26	-26	-19	-19	0
Income tax		$m	0	0	0	0	0	0	14	7	-241	-144	-54	-73	-74	-70	-66	-64	-59	-56	-50	-43	-32	-29	-25	-16	-17	-17	-18	-15	-11	-12	1
Net contractor cashflow		$m	**0**	**0**	**0**	**0**	**0**	**0**	**-362**	**-396**	**234**	**439**	**242**	**247**	**226**	**199**	**178**	**162**	**143**	**130**	**113**	**97**	**73**	**63**	**54**	**37**	**37**	**36**	**36**	**30**	**23**	**23**	**1**
Tullow equity		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Tullow cashflow		$m	**0**	**0**	**0**	**0**	**0**	**0**	**-362**	**-396**	**234**	**439**	**242**	**247**	**226**	**199**	**178**	**162**	**143**	**130**	**113**	**97**	**73**	**63**	**54**	**37**	**37**	**36**	**36**	**30**	**23**	**23**	**1**

VALUE	PV of EV FCF	
Gross field	652	$m
TLW	652	$m
EV / 2P remaining working interest	2,7	$/boe
Discount rate	8,9%	
2P reserves data		
Initial reserves - gross	250	mboe
Remaining gross reserves	243	mboe
Remaining reserves working interest	243	mboe

Tax			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Revenue		$m	0	0	0	0	0	0	0	124	1160	1663	2019	2185	2043	1829	1663	1544	1378	1211	998	855	760	665	570	475	475	475	475	475	356	356	0
Less costs		$m	0	0	0	0	0	0	0	-6	-63	-90	-109	-118	-111	-99	-90	-84	-75	-66	-54	-46	-41	-36	-31	-26	-26	-26	-26	-26	-19	-19	0
Less depreciation		$m	0	0	0	0	0	0	-38	-118	-182	-183	-146	-117	-94	-75	-60	-48	-38	-31	-25	-20	-16	-13	-10	-8	-6	-5	-4	-3	-3	-2	-2
Gvmt share		$m		0	0	0	0	0	0	-21	-246	-989	-1613	-1746	-1632	-1461	-1328	-1233	-1101	-960	-780	-669	-614	-537	-460	-396	-396	-396	-396	-404	-303	-303	0
Taxable base		$m	0	0	0	0	0	0	-38	-21	669	401	150	204	206	194	184	179	164	155	139	120	89	79	69	46	47	48	49	42	32	32	-2
Tax rate	36%	%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%	36%
Tax		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**14**	**7**	**-241**	**-144**	**-54**	**-73**	**-74**	**-70**	**-66**	**-64**	**-59**	**-56**	**-50**	**-43**	**-32**	**-29**	**-25**	**-16**	**-17**	**-17**	**-18**	**-15**	**-11**	**-12**	**1**

Capex & depreciation	Total		2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Starting NBV of capitalized capex	1250	$m	0	0	0	0	0	0	0	338	720	914	731	585	468	374	299	239	192	153	123	98	78	63	50	40	32	26	21	16	13	11	8
Capex added	1250	$m	0	0	0	0	0	0	375	500	375	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation @ 20%		$m	0	0	0	0	0	0	-38	-118	-182	-183	-146	-117	-94	-75	-60	-48	-38	-31	-25	-20	-16	-13	-10	-8	-6	-5	-4	-3	-3	-2	-2
Closing NBV		$m	0	0	0	0	0	0	338	720	914	731	585	468	374	299	239	192	153	123	98	78	63	50	40	32	26	21	16	13	11	8	7
Capex phasing	W guidance	100%	0%	0%	0%	0%	0%	0%	30%	40%	30%	0%	0%	0%	0%	0%	0%																
Capex	5	$/boe																															
Abandonment costs	1,0																																

Actual Costs			2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Variable production costs/bbl		$/bbl	0,0	4,0	4,4	4,6	4,9	5,0	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1	5,1
Production costs		$m	0	0	0	0	0	0	0	6	63	90	109	118	111	99	90	84	75	66	54	46	41	36	31	26	26	26	26	26	19	19	0
Capex Including Exploration	1250	$m	0	0	0	0	0	0	375	500	375	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Exploration		$m	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Abandonment costs																																	
Total costs		**$m**	**0**	**0**	**0**	**0**	**0**	**0**	**375**	**506**	**438**	**90**	**109**	**118**	**111**	**99**	**90**	**84**	**75**	**66**	**54**	**46**	**41**	**36**	**31**	**26**	**26**	**26**	**26**	**26**	**19**	**19**	**0**

Tullow Equity		100%	2008A	2009A	2010A	2011A	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E
Net Production		**kboe/d**	0	0	0	0	0	0	0	3	34	48	58	63	59	53	48	45	40	35	29	25	22	19	16	14	14	14	14	14	10	10	0
Net revenues		$m	0	0	0	0	0	0	0	111	986	778	533	577	539	483	439	408	364	327	280	240	194	170	146	109	109	109	109	101	76	76	0
Net opex		$m	0	0	0	0	0	0	0	-6	-63	-90	-109	-118	-111	-99	-90	-84	-75	-66	-54	-46	-41	-36	-31	-26	-26	-26	-26	-26	-19	-19	0
Net capex		$m	0	0	0	0	0	0	-375	-500	-375	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Tax		$m	0	0	0	0	0	0	0	0	-314	-249	-181	-211	-203	-185	-171	-162	-146	-132	-113	-97	-80	-70	-61	-46	-47	-47	-48	-45	-34	-34	0
Net cash		$m	0	0	0	0	0	0	-375	-396	234	439	242	247	226	199	178	162	143	130	113	97	73	63	54	37	37	36	36	30	23	23	0

Appendix 45 - Total NAV Output

Net Asset Value (NAV)		Spud date	P50 gross resources	P50 working interest	P50 entitled reserves	EV/bbl working interest	EV/bbl entitled	Risk weighting	Unrisked EV	Risked EV	Risked EV/sh	% of group value	Unrisked EV/sh	NAV upside	% NAV upside	Entitlement factor	Field WI (eq)	Currency
Country	**Field**		**mmboe**	**mmboe**	**mmboe**	**$/boe**	**$/boe**	**%**	**$m**	**$m**	**p/sh**	**%**	**p/sh**	**p/sh**	**%**	**%**	**%**	**£/$**
Ivory Coast	Espoir		61	13	7	17,5	33	100%	229	229	16	0,9%				54%	21%	1,6
Ivory Coast			**61**	**13**	**7**	**17,5**	**33**	**100%**	**229**	**229**	**16**	**0,9%**	**16**			**54%**	**21%**	**1,6**
Equatorial guinea	Ceiba		64	9	8	23,1	27	100%	210	210	14	0,8%				87%	14%	1,6
Equatorial guinea	Okume complex		122	17	13	25,3	34	100%	440	440	30	1,7%				75%	14%	1,6
Equatorial Guinea			**186**	**26**	**21**	**24,5**	**60**	**100%**	**650**	**650**	**45**	**2,5%**	**45**			**81%**	**14%**	**1,6**
Gabon	All fields		52	52	38	12,1	17	100%	632	632	44	2,5%				72%	100%	1,6
Gabon			**52**	**52**	**38**	**12,1**	**17**	**100%**	**632**	**632**	**44**	**2,5%**	**44**			**72%**	**100%**	**1,6**
Congo	M'Boundi		88	10	7	25,6	37	100%	247	247	17	1,0%				69%	11%	1,6
Congo			**88**	**10**	**7**	**25,6**	**37**	**100%**	**247**	**247**	**17**	**1,0%**	**17**			**69%**	**11%**	**1,6**
Mauritania	Cinguetti		13	3	2	23,0	28	100%	65	65	5	0,3%				83%	22%	1,6
Mauritania			**13**	**3**	**2**	**23,0**	**28**	**100%**	**65**	**65**	**5**	**0,3%**	**5**			**83%**	**22%**	**1,6**
UK	UK North Sea gas fields (CMS & TH)		32	32	32	9,9	10	100%	318	318	22	1,2%				100%	100%	1,6
UK			**32**	**32**	**32**	**9,9**	**10**	**100%**	**318**	**318**	**22**	**1,2%**	**22**			**100%**	**100%**	**1,6**
The Netherlands	Nuon acquisition - producing fields		180	27	27	5,5	6	100%	150	150	10	0,6%				100%	15%	1,6
The Netherlands			**180**	**27**	**27**	**5,5**	**6**	**100%**	**150**	**150**	**10**	**0,6%**	**10**			**100%**	**15%**	**1,6**
Ghana UNIT	Jubilee Phase 1&1a		470	167	167	27,4	26	100%	4.356	4.356	300	16,9%				100%	35%	1,6
Ghana UNIT	Jubilee P50 remainder - Phase 1b		205	78	78	18,1	18	100%	1.419	1.419	98	5,5%				100%	38%	1,6
Ghana DWT	TEN		280	140	140	17,4	17	100%	2.435	2.435	168	9,5%				100%	50%	1,6
Ghana			**955**	**385**	**385**	**21,3**	**62**	**100%**	**8.210**	**8.210**	**566**	**31,9%**	**566**			**100%**	**40%**	**1,6**
Uganda	Ugandan Development		1.100	367	152	5,7	14	100%	2.105	2.105	145	8,2%				41%	33%	1,6
Uganda			**1.100**	**367**	**152**	**5,7**	**14**	**100%**	**2.105**	**2.105**	**145**	**8,2%**	**145**			**41%**	**33%**	**1,6**
Commercial NAV			**2.667**	**915**	**670**	**13,8**	**18,8**	**100%**	**12.606**	**12.606**	**869**	**48,9%**	**869**				**34,3%**	**1,6**
Mauritania	Tiof		250	54	36	9,6	15	50%	520	260	18	1,0%	36	18	1%	66%	22%	1,6
Mauritania	All other fields		700	350	231	9,6	15	40%	3.370	1.348	93	5,2%	232	139	8%	66%	50%	1,6
Mauritania			**950**	**404**	**267**	**9,6**	**15**	**41%**	**3.890**	**1.608**	**111**	**6,2%**	**268**	**157**	**9%**	**66%**	**43%**	**1,6**
Namibia	Kudu		500	155	155	4,6	4,6	60%	709	425	29	1,7%	49	20	1%	100%	31%	1,6
Namibia			**500**	**155**	**155**	**4,6**	**5**	**60%**	**709**	**425**	**29**	**1,7%**	**49**	**20**	**1%**	**100%**	**31%**	**1,6**
Sierra Leone	Mercury		75	15	15	18,7	18,7	50%	280	140	10	0,5%	19	10	1%	100%	20%	1,6
Sierra Leone	Jupiter		83	17	17	18,7	18,7	60%	310	186	13	0,7%	21	9	0%	100%	20%	1,6
Sierra Leone			**158**	**32**	**32**	**18,7**	**19**	**55%**	**590**	**326**	**22**	**1,3%**	**41**	**18**	**1%**	**100%**	**20%**	**1,6**
Ghana WC3	Mahogany East Area		80	21	21	14,0	14,0	80%	295	236	16	0,9%	20	4	0%	100%	26%	1,6
Ghana WC3	Teak P50		120	32	32	14,0	14,0	80%	443	355	24	1,4%	31	6	0%	100%	26%	1,6
Ghana WC3	Akasa-1		32	8	8	14,0	14,0	80%	118	95	7	0,4%	8	2	0%	100%	26%	1,6
Ghana UNIT	Jubilee- Associated gas + TEN		173	66	66	7,4	7,4	50%	492	246	17	1,0%	34	17	1%	100%	38%	1,6
Ghana			**405**	**127**	**127**	**10,6**	**11**	**69%**	**1.349**	**931**	**64**	**3,6%**	**93**	**29**	**2%**	**100%**	**31%**	**1,6**
Kenya	Ngamia-1 (Block 10BB)		35	18	17,5	3,5	3,5	50%	61	31	2	0,1%	4	2	0%	100%	50%	1,6
Kenya			**35**	**18**	**18**	**3,5**	**4**	**50%**	**61**	**31**	**2**	**0,1%**	**4**	**2**	**0%**	**100%**	**50%**	**1,6**
French Guiana	Guyane Maritime- Zaedyus		175	48	48,125	12,9	12,9	80%	623	499	34	1,9%	43	9	0%	100%	28%	1,6
French Guiana			**175**	**48**	**48**	**12,9**	**13**	**80%**	**623**	**499**	**34**	**1,9%**	**43**	**9**	**0%**	**100%**	**28%**	**1,6**
UK	K4		25	6	6	6,5	6,5	50%	36	18	1,3	0,1%	2,5	1,3	0%	100%	23%	1,6
UK Thames	Bure N		2	1	1	6,5	6,5	50%	9	4	0,3	0,0%	0,6	0,3	0%	100%	67%	1,6
UK CMS	Katy (formerly Harrison)		20	5	5	6,5	6,5	80%	29	23	1,6	0,1%	2,0	0,4	0%	100%	23%	1,6
UK			**47**	**11**	**11**	**6,5**	**6**	**62%**	**74**	**46**	**3**	**0,2%**	**5**	**2**	**0%**	**100%**	**24%**	**1,6**
Netherlands	Nuon fields incl Epidote		97	15	15	3,6	3,6	50%	53	26	1,8	0,1%	3,6	1,8	0%	100%	15%	1,6
Netherlands			**97**	**15**	**15**	**3,6**	**4**	**50%**	**53**	**26**	**2**	**0,1%**	**4**	**2**	**0%**	**100%**	**15%**	**1,6**
Contingent NAV			**2.367**	**810**	**672**	**9,1**	**10,9**	**53%**	**7.349**	**3.892**	**268**	**15,1%**	**506**	**238**	**13%**		**34%**	

Liberia	Cobalt - Strontium	4Q12	165	41	41	12,5	12	30%	515	154	11	0,6%	35	25	1%	100%	25%	1,6
Liberia			**165**	**41**	**41**	**12**	**12**	**30%**	**515**	**154**	**11**	**0,6%**	**35**	**25**	**1%**	**100%**	**25%**	**1,6**
Ivory Coast	Paon	2Q12	205	92	52	11,5	11,5	30%	603	181	12,5	0,7%	41,5	29,1	2%	57%	45%	1,6
Ivory Coast	Kosrou	progress	265	59	34	11,5	11,5	30%	387	116	8,0	0,5%	26,7	18,7	1%	57%	22%	1,6
Ivory Coast			**470**	**152**	**86**	**7**	**12**	**30%**	**990**	**297**	**20**	**1,2%**	**68**	**48**	**3%**	**57%**	**32%**	**1,6**
Ghana DWT	Ntomme, Owo, Enyenra appraisal	In progress	400	200	200	17,4	17,4	80%	3.479	2.783	191,8	10,8%	239,8	48,0	3%	100%	50%	1,6
Ghana DWT	Tweneboa Deep	3Q12	120	60	60	14,0	14,0	60%	838	503	34,7	2,0%	57,8	23,1	1%	100%	50%	1,6
Ghana DWT	Sapele-1	4Q12	75	37	37	14,0	14,0	60%	524	314	21,7	1,2%	36,1	14,4	1%	100%	50%	1,6
Ghana DWT	Wawa 1	2Q12	60	30	30	14,0	14,0	60%	419	252	17,3	1,0%	28,9	11,6	1%	100%	50%	1,6
Ghana WC3	Teak-4	1H12	100	26	26	14,0	14,0	50%	369	185	12,7	0,7%	25,5	12,7	1%	100%	26%	1,6
Ghana			**755**	**354**	**354**	**16**	**16**	**72%**	**5.630**	**4.037**	**278**	**15,7%**	**388**	**110**	**6%**	**100%**	**47%**	**1,6**
WAP	Jubilee/Zaedyus analogues	2013	5.600	1.459	1459	10,9	10,9	20%	15.925	3.185	219,5	12,4%	1097,5	878,0	49%	100%	26%	1,6
West African "Jubilee" Play			**5.600**	**1.459**	**1459**	**11**	**11**	**20%**	**15.925**	**3.185**	**219**	**12,4%**	**1097**	**878**	**49%**	**100%**	**26%**	**1,6**
French Guiana	Zaedyus-2 appraisal	3Q12	170	47	47	12,9	12,9	30%	605	182	12,5	0,7%	41,7	29,2	2%	100%	28%	1,6
French Guiana	Zaedyus exploratory appriasal	2Q13	270	74	74	12,9	13	30%	961	288	20	1,1%	66	46	3%	100%	28%	1,6
French Guiana	Dasypus-1	4Q12	230	63	63	12,9	13	30%	819	246	17	1,0%	56	40	2%	100%	28%	1,6
Guyana	Jaguar Fan System	In progress	430	129	73	11,0	19	20%	1.413	283	19	1,1%	97	78	4%	57%	30%	1,6
Suriname	5 well campaign - Onshore Coronie	In progress	100	40	11	2,7	10,2	30%	107	32	2,2	0,1%	7,4	5,2	0%	26%	40%	1,6
South America			**1.200**	**353**	**268**	**11**	**15**	**26%**	**3.906**	**1.030**	**71**	**4,0%**	**269**	**198**	**11%**	**77%**	**29%**	**1,6**
Uganda	Ugandan exploration - various wells	2012	555	185	78	5,7	13,7	40%	1.062	425	29,3	1,6%	73,2	43,9	2%	42%	33%	1,6
Uganda			**555**	**185**	**78**	**6**	**14**	**40%**	**1.062**	**425**	**29**	**1,6%**	**73**	**44**	**2%**	**42%**	**33%**	**1,6**
Kenya	Mbawa (Block L8)	3Q12	230	46	46	6,0	6,0	30%	276	83	5,7	0,3%	19,0	13,3	1%	100%	20%	1,6
Kenya	Paipai (Block 10A)	2Q12	115	58	58	6,0	6,0	30%	345	104	7,1	0,4%	23,8	16,6	1%	100%	50%	1,6
Kenya	Upside potential		1.000	300	300	6,0	6,0	40%	1.800	720	49,6	2,8%	124,0	74,4	4%	100%	30%	1,6
Kenya			**1.345**	**404**	**404**	**6**	**6**	**37%**	**2.421**	**906**	**62**	**3,5%**	**167**	**104**	**6%**	**100%**	**30%**	**1,6**
Ethiopia	Sabisa	4Q12	140	70	70	6,5	6,5	20%	455	91	6,3	0,4%	31,4	25,1	1%	100%	50%	1,6
Ethiopia			**140**	**70**	**70**	**7**	**7**	**20%**	**455**	**91**	**6**	**0,4%**	**31**	**25**	**1%**	**100%**	**50%**	**1,6**
Mauritania	Sidewinder	4Q12	205	46	30	9,6	9,6	20%	292	58	4,0	0,2%	20,1	16,1	1%	66%	22%	1,6
Mauritania			**205**	**46**	**30**	**6**	**10**	**20%**	**292**	**58**	**4**	**0,2%**	**20**	**16**	**1%**	**66%**	**22%**	**1,6**
Gabon	Gnondo	4Q12	40	21	17	7,9	7,9	50%	131	66	4,5	0,3%	9,1	4,5	0%	78%	53%	1,6
Gabon			**40**	**21**	**17**	**6**	**8**	**50%**	**131**	**66**	**5**	**0,3%**	**9**	**5**	**0%**	**78%**	**53%**	**1,6**
Netherlands	K8, Sigma, Vincent	3Q12	35	11	11	3,6	3,6	50%	38	19	1,3	0,1%	2,6	1,3	0%	100%	30%	1,6
Netherlands			**35**	**11**	**11**	**4**	**4**	**50%**	**38**	**19**	**1**	**0,1%**	**3**	**1**	**0%**	**100%**	**30%**	**1,6**
Exploration NAV			**10.510**	**3.095**	**2816**	**10,1**	**11,1**	**33%**	**31.364**	**10.269**	**708**	**39,9%**	**2.162**	**1.454**	**82%**		**29,4%**	
Less exploration costs 2012									-1.000	-1.000	-69	-4%						1,6
Net exploration NAV			**10.510**	**3.095**	**2816**	**9,8**	**10,8**	**31%**	**30.364**	**9.269**	**639**	**36,0%**	**2.162**	**1.454**	**82%**			
Tariff income value	PV of future post tax CF								241	241	17	0,9%	17					
Hedging value isolated	PV of future hedging profit / loss								274	274	19	1,1%	19					
Less corporate costs	6x present value								-759	-759	-52	-3,0%	-52					
(Net debt) / net cash	Adjusted 31 December 2011								164	164	11	1%	11					
Estimated net sales revenue Asian Assets									80	80	6	0,3%	6					
Net financial items									**-0,4**	**-0,4**	**-0,1**	**0%**	**-0,1**					**1,6**
Core (Commercial) NAV									**12.606**	**12.606**	**869**	**49%**	**869**	**-**	**-**			**1,6**
Contingent NAV									**7.349**	**3.892**	**268**	**15%**	**506**	**238**	**13%**			**1,6**
Exploration NAV									**30.364**	**9.269**	**639**	**36%**	**2.162**	**1.523**	**86%**			**1,6**
Risked NAV			**15.544**	**4.819**	**4158**				**50.319**	**25.767**	**1.776**	**100%**	**3.537**	**1.761**	**99%**			
									Number of shares (m)		905							