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March 16, 2020

The Honorable Jay Clayton, Chair
Commissioner Hester M. Peirce
Commissioner Elad L. Roisman
Commissioner Allison H. Lee

U.S. Securities and Exchange Commission 100 F Street, NE
Washington, DC 20549

Re: Release No. 34-87783; File No. S7-24-19 Disclosure of Payments by Resource Extraction Issuers

Dear Chair Clayton and Commissioners:

We are writing to share research that responds to the request for comment on the proposed Rule 13(q) to implement Section 1504 of the Dodd-Frank Wall Street Reform and Consumer Protection Act.

The following research provides evidence of the analytical value of extractives payment disclosures for securities analysts. This submission is made in response to Question 97 in the proposed rules for Section 13(q) published in the Federal Register on January 15, 2020[1]. Question 97 asked, "Are there studies on the potential effects of the proposed rules, the disclosure rules under the EU Directives or ESTMA, or EITI compliance on efficiency, competition, and capital formation?" The attached report details the potential benefits of extractives payment data on market efficiency, competition and capital formation.

This research is submitted in the hope that it will help inform the economic analysis included in the final rule, particularly with regard to the benefits securities analysts might realize with Section13(q) data, and especially if disclosed in a manner consistent with the Europe Union (Directive 2013/34/EU), United Kingdom (The Payments to Governments and Miscellaneous Provisions Regulations 2014)[2] and Canadian (Extractive Sector Transparency Measures Act)[3] laws. This research is referenced in the March 16, 2020 comment letter from Aviva Investors et al and reflects the merger to two earlier reports on the same topic.

We are very eager to expand on these and related points with the SEC as it finalizes the rules for the implementation of Section 13(q). We would welcome the opportunity to be in touch in this regard at your convenience.

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[1] U.S. Federal Register. Disclosure of Payments by Resource Extraction Issuers - Proposed Rule. January 15, 2010. p. 2564. https://www.govinfo.gov/content/pkg/FR-2020-01-15/pdf/2019-28407.pdf
[2] FCA: Statutory Instrument No 3293, The Payments to Governments and Miscellaneous Provisions Regulations 2014 (15 Dec. 2014) http://www.legislation.gov.uk/uksi/2014/3293/pdfs/uksi_20143293_en.pdf
[3] Extractive Sector Transparency Measures Act (22 Dec. 2015) http://laws-lois.justice.gc.ca/PDF/E-22.7.pdf.

Sincerely,

Alexander Schay
Managing Director
W.K. Associates, Inc.

CC:
Ms. Vanessa A. Countryman, Secretary, Securities and Exchange Commission
Mr. William Hinman, Director, Division of Corporate Finance
Mr. Barry Summer, Associate Director, Division of Corporation Finance
Ms. Elizabeth Murphy, Associate Director, Division of Corporate Finance
Mr. Elliot Staffin, Special Counsel, Division of Corporate Finance

W.K. Associates, Inc.

Version 4.0 (LSE: TLW) March 16, 2020

Disclosure of Payments by Resource Extraction Issuers

Alexander Schay
Managing Director
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Emerging Markets Globe

Summary: In recent years, the European Union, the United Kingdom, Canada and Norway have all passed laws implementing payment transparency legislation that requires companies, primarily in extractive industries, to disclose remittances to governments. This report attempts to assess the value of these disclosures for equity and fixed income analysts. The report consists of two parts:

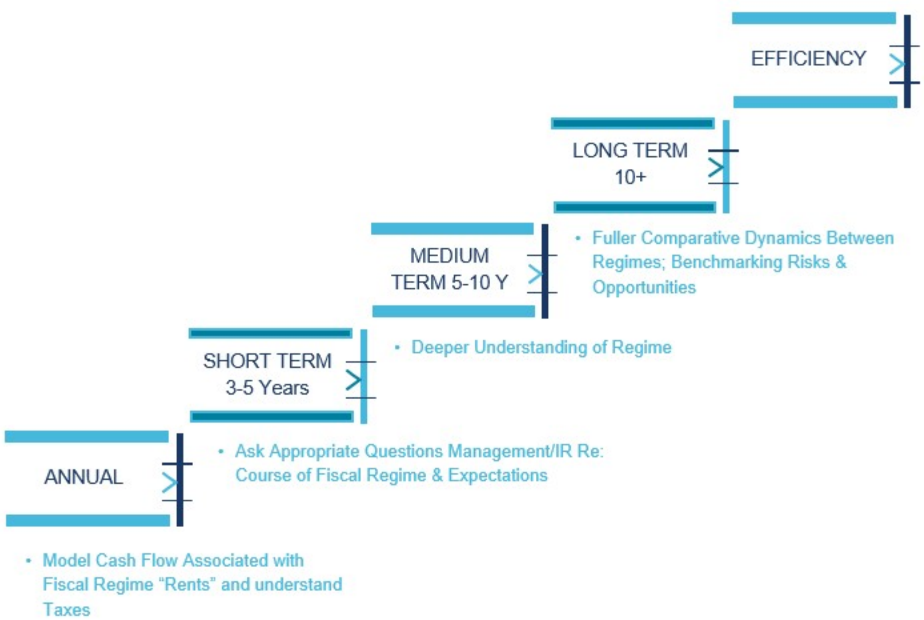
- **The construction of a model to assess the impact of government remittance disclosures on the value of an oil and gas company, Tullow Oil (LSE: TLW).**

- **An assessment of the potential valuation insights that can be gleaned from payment transparency data.**

Executive Summary

Efficient pricing of risk is predicated on transparency. While investors stand to benefit from payment transparency data today, the most profound insights will come in the medium to long-term as data aggregate in the public domain. Understanding the complete cash flow history and performance of companies under various oil and gas fiscal systems will allow analysts to benchmark project, country and regional performance, as well as better understand the risk of changes to these regimes.

Executive Summary:
Long Run Benefits to Risk Pricing & Market Efficiency



Source: WKA Analysis

Since 2013, the European Union (EU), the United Kingdom (UK), Canada and Norway have all implemented laws requiring public disclosure of project-level payment data for extractives industry firms. This report outlines a use case for these data, as well as an assessment of the impact of government remittances on the valuation of a representative oil and gas firm. **Tullow Oil (LSE: TLW)**. The UK "Reports on Payments to Governments Regulations" came into force on December 1st, 2014, making the nation one of the first to implement a payment disclosure transparency regime, providing analysts with four years of disclosures for LSE-listed firms.

On a Discounted Cash Flow (DCF) basis, we valued Tullow Oil at $3.50 per share, or a market cap of $4.7 billion and an enterprise value of $8.2 billion. At the time of original analysis, Tullow's market value was $3.06 per share (November, 2018). By far, the largest sensitivity in the model was a 10% change in year-1 energy price, which amounts to +/- 50-60% in equity value. Similarly, varying all operating costs (except for general & administrative costs) by 10% per BOE lead to a 35-40% change in equity value. Energy-price-based changes in revenue growth assumptions are always accompanied by concurrent changes in the cost of fixed assets and operating costs. Keeping this in mind, a parallel 10% change in energy price in the revenue line accompanied by a 10% change in operating expenses and F&D costs per BOE produces a 15-18% change in equity value per share.

Varying flow rate (BOE per year / developed reserves) by 10% produced a 10% change in equity value. **Finally, varying the host country sovereign take rate by 10% produced a 7% change in equity value.** This was calculated by taking the sum of all designated payments to foreign governments (known as remittances) and dividing that number by the total revenue from these same governments. In Tullow's case the remittance total was 13.2% of all country revenue. Increasing this sovereign "take rate" to 14.5% (an increase of 10%) produced a 7% decline in total equity value (a decrease in these outlays would positively affect equity value). This is significant because Tullow's actual remittance fluctuations were 30% on an annualized basis from 2015-2018.

That the sovereign take rate has such an impact on the model is unsurprising. All the "newly" reported accounts under the UK "Reports on Payments to Governments" (such as production entitlements, royalties and infrastructure improvement payments) are currently consolidated into standard income statement line items. Payment transparency regulations require that certain accounts, formerly consolidated, be unbundled into separate disclosures in the annual report.

Integration of payment transparency accounts into the valuation model yield the following insights:

1. **Cash Flow Forecasting** -- Since these payments often represent significant annual cash outflows (in 2016 aggregate remittances for Tullow were 50% of the company's total operating cash flow), analysts would be wise to try and model the future path of these accounts in order to improve forecasting. While annual Take Rate's fluctuate dramatically, the rolling average between countries is surprisingly consistent, with Ghana and Gabon both at 19% and Equatorial Guinea at 15%.

2. **Taxes** -- Patterns in the data begin to emerge that can prompt questions about the use of income tax offsets, depending on the petroleum fiscal regime. In Ghana, Tullow used the costs of developing the Tweneboa-Enyenra-Ntomme (TEN) field to offset profits from Jubilee in 2015, thus lowering taxable income. Although common industry practice, it's notoriously difficult for analysts to model. Understanding the historical trajectory and use of these offsets, especially regarding specific projects, can aid future projections and prompt appropriate questions of management. In addition, payments to governments under petroleum fiscal regimes can account for most of the income taxes reported on the the Income Statement. In Tullow's case this

represented 95% of its total tax bill for 2018. A better understanding of this moving part can aid the analyst's forecasts.

- **Benchmarking Fiscal Regimes & Risk Assessment** -- The simple aggregate Take Rate figure is instructive because it shows the overall path of government remittances for a company. In Tullow's case, these payments have steadily lessened as the company develops its infrastructure and oil begins to flow. Knowing where a company is in this cycle can set expectations for future capital allocation. More importantly, over time, understanding the complete performance of petroleum fiscal regimes will allow analysts to benchmark countries and regions, as well as understand the risk of changes to these regimes.

Part I: Model Construction & Materiality

Introduction:

In recent years, the European Union (EU), the United Kingdom (UK), Canada and Norway have all passed laws implementing payment transparency legislation that requires companies, primarily in extractive industries, to disclose remittances to governments. This report attempts to assess the value of these disclosures for equity and fixed income analysts. The report consists of two parts: (1). The construction of a model to assess the impact of government remittance disclosures on the value of an oil & gas company, and (2). An assessment of the potential valuation insights that can be gleaned from payment transparency data.

After a review of the operations, governance practices, financial structure & prospects of **Tullow Oil (LSE: TLW)** we confirmed that the company was a suitable candidate for analysis. The UK "Reports on Payments to Governments Regulations" came into force on December 1, 2014, making the nation one of the first to implement a payment transparency disclosure regime.[1] Below is a discussion of our primary method of valuation, which is a discounted cash flow analysis. The discussion will include a treatment of the primary drivers within the model, including select sensitivities. We also provided a comparables-driven valuation of Tullow as a check on the output of the model.

Construction:

Discounted cash flow (DCF) analysis is widely accepted within the energy and extractive industries. This form of analysis is not only appropriate to the assets but PV-10 is a ubiquitous model in industry

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[1] This has provided analysts with four years of disclosures for LSE-listed companies, in contrast with other regimes implemented later.

regulatory disclosures[2]. Oil and mineral deposits are generally long-lived, with non-linear cash flows (regarding the timing of investment and payback periods). After a heavy upfront investment stage, marginal costs are usually very low and project-level cash flows are very high. Due to non-linearity of these cash flows and the long asset lives, we valued Tullow primarily using a 10-15 year explicit forecast period.

<u>Assumptions & Major Drivers:</u>

Commodity prices are by far the most important driver for extractive industries. These inputs drive revenues, the supply and demand reaction, and then the feedback loop back into prices. The analyst must be very careful to understand the sensitivity of the model to this set of assumptions. There are two main schools of thought in setting price assumptions in a long-term model. The first is to use the futures curve, which is normally in backwardation. This means future prices are expected to be higher than today. The analyst then sets each year's energy price equal to the futures price.

However, many analysts believe there is no predictive power in the futures curve and use today's spot price, rolling forward future spot prices at the rate of inflation. This implies no real pricing power for producers, which has been the de facto competitive position of the industry since the mid-19th century[3]. This approach has the benefit of simplicity and comports with the long-term economic reality of the industry. We have chosen this approach, setting crude prices to spot Brent and natural gas prices to the ICE UK natural gas spot price (for 2018).

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2 PV10 is the present value of estimated future oil and gas revenues, net of estimated direct expenses, discounted at an annual discount rate of 10%. This nomenclature is most commonly used in the energy industry and is used to estimate the present value of a company's proved oil and gas reserves. (Investopedia definition).

3 BP Statistical Review of World Energy 2018

These prices currently stand at $70.18 and $8.78, respectively (November 2018). We then roll these numbers forward at a global inflation rate of 2%. We have set 2018 Tullow production equal to the current 17-analyst consensus, at 87,000 barrels per day equivalent[4]. This implies 29 million barrels of crude produced for the year and 16.1 billion cubic feet of natural gas. As a percentage of developed reserves (flow rate), this implies 11.8% of developed oil reserves are drawn and 6% of natural gas reserve, for a total flow rate of 11%. We believe these flow rates are consistent with the range of flow rates for global conventional exploration & production (E&P) companies as well as the Tullow Oil consensus (see Figure 1).

Figure 1
Flow Rate Comps

2018E Total Production (MMBoe)
Source: Bloomberg

	2018	Flow Rate
Centennial Resources	22	30%
QEP Resources	52	23%
Anadarko Petroleum	243	22%
Diamondback	44	21%
WPX Energy	46	21%
EOG Resources	262	19%
Continental Resources	108	18%
Newfield Exploration	70	17%
Chesaeake Energy	188	17%
Marathon Oil	152	17%
Apache	170	17%
Concho Resources	96	16%
Noble Energy	128	15%
Chevron	1,060	14%
EQT Corp	250	13%
Laredo	25	13%
Pioneer Natural Resources	117	13%
Occidental Petroleum	240	12%
Southwestern Energy	159	12%
Cabot Oil & Gas	123	12%
ConocoPhillips	458	12%
Devon Energy	196	11%
Tullow Oil	31	11%
ExxonMobil	1,394	10%
Range Resources	135	10%
Denbury Resources	22	10%

Source: Bloomberg

[4] Bloomberg

From this point forward, production is determined by a flow rate assumption (which we keep constant) and the company's proficiency in finding & developing resources (F&D). Figure 2 indicates 2017 F&D costs per BOE across a range of E&P organizations, with "oilier" E&Ps and integrated energy companies at the higher end of the range and "gassier" E&Ps at the bottom end.

Figure 2
F&D Costs

2017A Total Finding & Development Costs (F&D) per BOE Source: Bloomberg	
Occidental Petroleum	$ 19.08
Denbury Resources	$ 18.59
QEP Resources	$ 13.85
ExxonMobil	$ 11.98
Marathon Oil	$ 11.65
Continental Resources	$ 11.50
Apache	$ 11.22
Anadarko Petroleum	$ 10.75
Concho Resources	$ 10.46
Chevron	$ 9.69
Laredo	$ 8.50
WPX Energy	$ 7.38
Pioneer Natural Resources	$ 7.26
Devon Energy	$ 6.50
EOG Resources	$ 6.33
Centennial Resources	$ 5.47
Newfield Exploration	$ 4.99
ConocoPhillips	$ 4.85
Chesaeake Energy	$ 3.00
Noble Energy	$ 2.88
Range Resources	$ 1.88
Cabot Oil & Gas	$ 1.83

Source: Bloomberg

After a period of challenging F&D conditions, we assume Tullow falls into the "oilier" end of the range. We also adjust for the fact that most of its activities are in Frontier countries, versus largely developed market comps in Figure 2.

We assume global inputs such as steel inflate at 2% and local inputs inflate at 8-10%, in-line with CPI inflation rates in Bight of Benin countries such as Ghana, Togo and Nigeria. This results in F&D cost per BOE inflating at 5% annually.

Figure 3
WK Associates F&D Model

	Dec 2018E	Dec 2019E	Dec 2020E	Dec 2021E	Dec 2022E	Dec 2023E	Dec 2024E
Finding & Development							
Development cost	$ 450	$ 538	$ 941	$ 1,411	$ 1,552	$ 1,708	$ 1,878
Per BOE	$13.00	$ 13.65	$ 14.33	$ 15.05	$ 15.80	$ 16.59	$ 17.42
YoY growth		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Exploration cost	$ 100	$ 95	$ 166	$ 249	$ 274	$ 301	$ 331
Per BOE	$ 2.00	$ 2.10	$ 2.21	$ 2.32	$ 2.43	$ 2.55	$ 2.68
YoY growth		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Total F&D expenditures	$ 550	$ 633	$ 1,107	$ 1,660	$ 1,826	$ 2,009	$ 2,210
YoY growth		15.0%	75.0%	50.0%	10.0%	10.0%	10.0%
Per BOE	$ 6.50	$ 7.48	$ 7.85	$ 8.25	$ 8.66	$ 9.09	$ 9.55
YoY growth		15.1%	5.0%	5.0%	5.0%	5.0%	5.0%
DD&A	$ 518	$ 554	$ 569	$ 638	$ 772	$ 914	$ 1,065
Capex / DD&A	106%	114%	195%	260%	236%	220%	207%

Source: WKA

We assume near-term reserve replacement at 150-300%, which is slightly aggressive and subject to downward revision if costs are not kept under control. Near-term, we prefer to err on the liberal side in order to account for the company's exit from a heavy period of reservoir investment. In addition, we consider a longer-term slope in F&D costs above global energy prices (due to higher local inflation rates). Over time, capex accelerates to 200% or more of depreciation, depletion, and amortization (DD&A) to account for increased investment, long-lived assets, and local inflation rates.

Over five and ten years, these assumptions lead to 5% to 6.5% production growth and 7-8% reserve growth, which produce 13-15% growth in oil & gas revenue (about 200 basis points of which come from positive energy price development in 2018). Among a wide range of E&P companies, Tullow has the highest production netback (revenue less cash operating costs, see Figure 4). This is the result of its high mix of crude output (90%+) and its offshore operations in lower-cost West Africa.

Figure 4
Production Results

2017A Production Results per BOE Source: Bloomberg	Revenue	Production Cost	Operating Netback
Tullow Oil	$ 49.83	$ 15.53	$ 34.30
Diamondback	$ 41.02	$ 7.36	$ 33.66
Centennial Resources	$ 36.96	$ 8.49	$ 28.47
Concho Resources	$ 36.77	$ 8.63	$ 28.14
Continental Resources	$ 33.68	$ 6.01	$ 27.67
ConocoPhillips	$ 42.04	$ 14.50	$ 27.53
Anadarko Petroleum	$ 38.74	$ 11.36	$ 27.38
Pioneer Natural Resources	$ 35.39	$ 8.11	$ 27.28
Chevron	$ 37.40	$ 10.91	$ 26.49
Denbury Resources	$ 49.51	$ 23.94	$ 25.57
Apache	$ 35.27	$ 10.36	$ 24.91
WPX Energy	$ 32.61	$ 7.98	$ 24.63
Laredo	$ 29.22	$ 5.31	$ 23.91
Occidental Petroleum	$ 35.82	$ 13.02	$ 22.80
EOG Resources	$ 35.58	$ 12.81	$ 22.77
ExxonMobil	$ 35.71	$ 14.47	$ 21.24
Newfield Exploration	$ 31.22	$ 10.24	$ 20.98
Marathon Oil	$ 28.65	$ 8.73	$ 19.92
Noble Energy	$ 29.19	$ 9.73	$ 19.47
Devon Energy	$ 25.98	$ 9.20	$ 16.79
QEP Resources	$ 29.13	$ 12.85	$ 16.29
Chesaeake Energy	$ 24.93	$ 10.61	$ 14.32
Range Resources	$ 17.81	$ 7.68	$ 10.13
Cabot Oil & Gas	$ 15.04	$ 5.40	$ 9.64
EQT Corp	$ 17.92	$ 9.05	$ 8.88
Southwestern Energy	$ 13.96	$ 5.96	$ 8.00

Source: Bloomberg

Over time, we escalate operating costs at the 5% inflation rate discussed above, though this is sensitive to the production sharing agreements (PSAs), predominantly with host countries Ghana and Gabon. We assume from reserve disclosures this will remain the case in the future.

Results:

On a DCF basis, we value Tullow Oil at $3.50 per share, or at a market cap of $4.7 billion and an enterprise value of $8.2 billion. At the time of this analysis Tullow's market value was $3.06 per share. Below are summary statistics from the model's output.

Figure 5
Summary Statistics

	5	10
Oil & gas revenue	$ 12,767	$ 35,928
Per BOE	$ 71.69	$ 76.72
Cash operating cost	$ 3,211	$ 9,825
Per BOE	$ 18.03	$ 20.98
% of revenue	25%	27%
EBIT	$ 5,953	$ 15,605
EBIT margin	47%	43%
Pretax income	$ 5,187	$ 14,149
Net income	$ 3,890	$ 10,612
DD&A	$ 3,051	$ 9,240
Net cash flow from operations	$ 9,136	$ 25,514
Capital expenditures	$ (5,776)	$ (18,041)
% of DD&A	189%	195%
Free cash flow	$ 2,594	$ 6,017
% of net income	67%	57%
Dividends	$ (506)	$ (2,469)
% of FCF	19%	41%
Average ROIC	8.7%	9.3%
Average WACC	12.2%	12.5%

Source: WKA

In order to provide a check on our analysis we assess comparable company valuations. Using a range of multiples from similar companies, the average valuation output is within 5% of our $3.50 per share DCF value (see Figure 6).

Figure 6
Comp Values

Comp Values (Median) Energy, E&P	2018	2019	Implied Value Tullow Oil 2018	2019
EV/Revenues	3.29x	2.89x	$ 2.21	$ 1.88
EV/EBIT	12.6x	10.0x	$ 5.56	$ 4.87
EV/EBITDA	6.1x	5.2x	$ 4.18	$ 3.62
P/E	16.2x	13.2x	$ 4.33	$ 4.71
FCF Yield	(10.1%)	(1.3%)		
Dividend Yield	1.4%			
Price/book	1.5x		$ 2.84	
EV / Proved develped reserves	$ 23.76		$ 2.17	
EV / flowing BOE	$ 237		$ 2.64	

Source: WKA

As a higher-margin company, Tullow is penalized on an EV/revenue basis, as each dollar of its revenue produces comparatively more dollars of operating income than comps (comps have lower EV/revenue multiples). This shows up in earnings-based measures, where comps have higher multiples, indicating either that option value is being discounted in comps to account for improvability (higher for comparables, lower for Tullow) or that higher risk is being embedded in Tullow.

We should note here we have used a base rate (risk-free rate) higher than USD- and GBP-based sovereign rates to account for the company sourcing most of its cash flow from Ghana and Gabon. In this case, we have used the Republic of Ghana 7 5/8% 2029 USD-denominated Eurodollar bond, which yields 8.2% to maturity currently. Rather than relying upon CAPM, we use the sum of two factors to stand in for the usual equity risk premium: a company-specific credit spread of 3.5% and an equity risk premium of 3.5% on top of that, which produces a 15% cost of equity across explicit time horizons.

Sensitivity Analysis:

For every 10% change in cost of equity (i.e., 14.8% declining to 13.3%), equity value is 25% sensitive (i.e., valuation increases from $3.50 to $4.38 per share).

By far, the largest sensitivity in the model is a 10% change in year-1 energy price, which amounts to +/- 50-60% in equity value. Similarly, varying all operating costs (except for general & administrative costs) by 10% per BOE leads to a 35-40% change in equity value. Many are surprised by this sensitivity but energy-price-based changes in revenue growth assumptions are always accompanied by concurrent changes in the cost of fixed assets and operating costs. Keeping this in mind, a parallel 10% change in energy price in the revenue line accompanied by a 10% change in operating expenses and F&D costs per BOE produces a 15-18% change in equity value per share.

Varying flow rate (BOE per year / developed reserves) by 10% produces a 10% change in equity value. **Finally, varying the host country sovereign take rate by 10% produces a 7% change in equity value.** This was calculated by taking the sum of all designated payments to foreign governments (known as remittances) and dividing that number by the total revenue from these same governments. In Tullow's case the remittance total was 13.2% of all country revenue. Increasing this sovereign take rate to 14.5% (an increase of 10%) produced a 7% decline in total equity value (a decrease in these outlays would positively affect equity value).

That the sovereign take rate has such an impact on the model is unsurprising. All the "newly" reported accounts under the UK "Reports on Payments to Governments"[5] (such as production entitlements, royalties and infrastructure improvement payments) are currently consolidated into standard income

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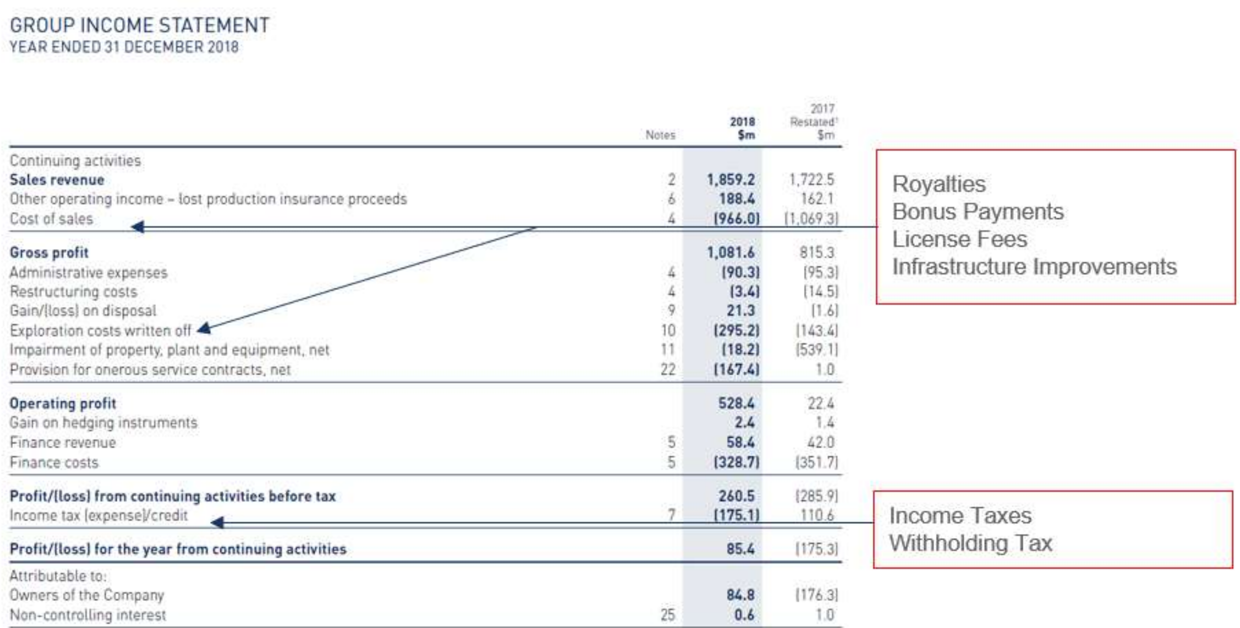
[5] The UK regulation "Report on Payments to Governments 2014" was the implementation rule for the European Union's "Directive 2013/34/EU" passed in June 2013

statement line items. The advent of payment transparency regulation requires that certain accounts, formerly consolidated, be unbundled into separate transparency disclosures in the annual report. However, companies are given significant latitude with respect to how they interpret and disclose these accounts.[6]

Figure 7
Government Remittance Accounts Unbundled



GROUP INCOME STATEMENT
YEAR ENDED 31 DECEMBER 2018

	Notes	2018 $m	2017 Restated[1] $m
Continuing activities			
Sales revenue	2	**1,859.2**	1,722.5
Other operating income – lost production insurance proceeds	6	**188.4**	162.1
Cost of sales	4	**(966.0)**	(1,069.3)
Gross profit		**1,081.6**	815.3
Administrative expenses	4	**(90.3)**	(95.3)
Restructuring costs	4	**(3.4)**	(14.5)
Gain/(loss) on disposal	9	**21.3**	(1.6)
Exploration costs written off	10	**(295.2)**	(143.4)
Impairment of property, plant and equipment, net	11	**(18.2)**	(539.1)
Provision for onerous service contracts, net	22	**(167.4)**	1.0
Operating profit		**528.4**	22.4
Gain on hedging instruments		**2.4**	1.4
Finance revenue	5	**58.4**	42.0
Finance costs	5	**(328.7)**	(351.7)
Profit/(loss) from continuing activities before tax		**260.5**	(285.9)
Income tax (expense)/credit	7	**(175.1)**	110.6
Profit/(loss) for the year from continuing activities		**85.4**	(175.3)
Attributable to:			
Owners of the Company		**84.8**	(176.3)
Non-controlling interest	25	**0.6**	1.0

Source: Tullow 2018 Annual Report & WKA

Figure 7 shows five of the more significant accounts and where they're consolidated in the income statement (please see additional detail in the Transparency Disclosure account descriptions below). Tullow's largest remittance to a foreign government in 2017 went to Ghana, understandable given that 63% of the company's total revenue came from projects in the country. The total government

[6] Details regarding these accounts were provided by Tullow Investor Relations

remittance is derived from summing various categories of payments. The major categories are shown below (all quotations are from Tullow 2017 Annual Report Transparency Disclosure):

- **Production Entitlements** – Payments governments receive as participants in a project. These entitlements can be in cash or in barrels of oil. As Tullow's disclosures state, this "includes non-cash royalties and state non-participating interest paid in barrels of oil or gas out of Tullow's working interest share of production in a license". Importantly, in Tullow's case these payments do not include the Government's or National Oil Company's working interest share in production. These payments can be significant, as the Ghana National Petroleum Corporation has a 15% stake in both Jubilee and TEN (Ghana's two major producing projects).[7] Tullow's barrel entitlements are largely noncash and the costs associated with those barrels are spread out over recognized revenue. For example, Ghana is permitted to take a 5% working interest share of production. Tullow is not entitled to those barrels and therefore does not recognize them as revenue but allocates the costs over its remaining share.

- **Income Taxes** – These represent the cash payment of income taxes in the year in which the tax has arisen or up to one year later. "Income taxes also include any cash tax rebates received from the government or revenue authority during the year". These taxes can fluctuate considerably due to oil prices and from offsets (i.e. "deductions against taxable income"). It's standard practice in the industry for frontier oil and gas companies to recover development costs. For instance, in 2015 Tullow offset costs associated with developing TEN against profits

[7] According to 2014 Extractive Industries Transparency Initiative report as well as https://resourcegovernance.org/blog/tullow-disclosure-yields-insight-ghana-oil-gas-sector

made on Jubilee, resulting in a large drop in income taxes paid. Income taxes paid under a petroleum fiscal regime are consolidated into the income tax account on the Income statement.

- **Royalties** – Cash paid to the government in the form of royalties are established within the Production Sharing Contract (PSC). These vary considerably based on the project, even within the same country. In 2017 no royalties were paid to Ghana but 83% of the remittances to Gabon came in the form of royalties. Royalties are consolidated into Cost of Sales on the Income Statement.

- **Bonus, License Fees & Infrastructure Improvement Payments** – Bonus payments are made as a result of achieving certain project milestones like contract signing or production targets. License fees are paid in order to secure access rights to a production area. Infrastructure improvement payments are designated outlays within a PSC for improving local infrastructure, such as roads, bridges, ports, schools and hospitals. Taken together these payments are relatively small (usually less than 5% of the total remittance). License fees are capitalized and then amortized over the life of the license.

All the above categories of disclosures are mandated by the European transparency directive. However, Tullow does make some voluntary disclosures that add to the total remittance figure. These include the following major categories:

- **VAT** – Representing net cash paid to the government during the year as value-added-tax.
- **Withholding Tax** – Amount paid as a credit against income taxes and can represent tax charged on services, interest, dividends or other distribution of profits. "The amount disclosed

is equal to the WHT return submitted by Tullow to governments with the cash payment made in the year the charge is borne". Withholding taxes under a petroleum fiscal regime are consolidated into the income tax account on the Income statement.

- **PAYE & National Insurance** – Payroll and employer taxes.
- **Carried Interests** – Payments made under a carrying agreement or PSC for the "cash settlement of costs owed by a government or NOC for their equity interest in a license".
- **Customs Duties** – These represent cash payments made for customs, excise or import duties typically associated with transport of goods into a country to service the oil and gas project.

The 10% change in the sovereign take rate noted above was for illustrative purposes. The aggregate changes in total remittances can vary quite widely based on the underlying variability in the categories indicated. For instance, total Tullow remittances dropped by almost 50% from 2016 to 2017[8]. The annualized change from 2015-2018 was 30%. Gaining a more detailed understanding of these accounts, as well as tracking their change over time, can give the analyst insight into the trajectory of future project costs that affect equity value, as well the ability to service debt.

[8] Tullow 2016 Annual Report Transparency Disclosure

Part 2: Valuation Insights

Introduction

A simple "take rate" was calculated for each country by dividing the sum of all government payments by total revenue (see Figure 8). This can serve as shorthand for government share, with numbers available in public filings.[9] Integration of payment transparency accounts into the valuation model yields the following insights:

3. **Cash Flow Forecasting** -- Since these payments often represent significant annual cash outflows (in 2016 aggregate remittances for Tullow were 50% of the company's total operating cash flow, see Figure 10) analysts would be wise to try and model the future path of these accounts in order to improve forecasting. While annual take rates fluctuate dramatically, the rolling average between countries is surprisingly consistent, with Ghana and Gabon both at 19% and Equatorial Guinea at 15% (see Figure 9).

4. **Taxes** -- Patterns in the data begin to emerge that can prompt questions about the use of income tax offsets, depending on the petroleum fiscal regime. In Ghana, Tullow used the costs of developing the Tweneboa-Enyenra-Ntomme (TEN) field to offset profits from Jubilee in 2015, thus lowering taxable income. Although common industry practice, it's notoriously difficult for analysts to model. Understanding the historical trajectory and use of these offsets can aid future projections, as well as prompt appropriate questions of Investor Relations and/or management.

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[9] Tullow has a section in its annual report entitled, "Transparency Disclosure" where these numbers can be found. This calculation of the "Take Rate", despite utilizing a cash figure in the numerator (government remittances) and an accrual figure (revenues) in the denominator, can be instructive for comparative purposes.

In addition, payments to governments under petroleum fiscal regimes constitute most income taxes paid on the Income Statement. In Tullow's case this represented 95% of its total tax bill for 2018.

- **Benchmarking Fiscal Regimes & Risk Assessment** -- The simple aggregate take rate figure is instructive because it shows the overall path of government remittances for a company. In Tullow's case, these payments have steadily lessened as the company develops its infrastructure and oil begins to flow. Knowing where a company is in this cycle can set expectations for future capital allocation. More importantly, over time, understanding the complete performance of petroleum fiscal regimes will allow analysts to benchmark countries and regions, as well as understand the risk of changes to these regimes.

Figure 8
Tullow Simple "Take Rate" Summary for Guinea, Gabon, Ghana

(000,000)	2015A	2016A	2017A	2018A
Equatorial Guinea Revenue	$ 176.10	$141.40	$ 92.20	$ 146.60
YoY change	-33.0%	-19.7%	-34.8%	59.0%
% of total	10.96%	10.4%	4.9%	7.2%
Remittances to government	$ 37.38	$ 8.98	$ 21.65	$ 12.98
Production Entitlements ($)				
Income Taxes	$ 37.38	$ 8.98	$ 21.65	$ 12.98
Royalties				
Bonus, License Fees, Infrastructure				
VAT				
Withholding Tax				
PAYE & National Insurance				
Carried Interests				
Customs Duties				
% of country revenue Total (Take Rate)	21.23%	6.35%	23.48%	8.85%
% average to date		14%	17%	15%
Production entitlements (Barrel)	0.50	0.48	0.46	0.49
Average Realized Oil Price	$ 67.00	$ 61.40	$ 58.30	$ 68.50
Total Value	$ 33.17	$ 29.17	$ 26.76	$ 33.43
% of country revenue	19%	21%	29%	23%
% of country revenue Remittance+Barrels	40%	27%	53%	32%
% average to date		34%	40%	38%
Gabon Revenue	$ 284.30	$241.20	$251.80	$ 213.60
YoY change	3.2%	-15.2%	4.4%	-15.2%
% of total	18%	18%	13.36%	10.43%
Remittances to government	$ 62.14	$ 48.80	$ 30.12	$ 46.24
Production Entitlements ($)				
Income Taxes	$ 17.90			$ 7.94
Royalties	$ 23.24	$ 18.35	$ 25.04	$ 30.20
Bonus, License Fees, Infrastructure	$ 20.00	$ 30.00	$ 5.00	$ 8.00
VAT	$ 0.34			
Withholding Tax	$ 0.07	$ 0.05	$ 0.03	$ 0.04
PAYE & National Insurance	$ 0.59	$ 0.41	$ 0.05	$ 0.06
Carried Interests				
Customs Duties				
% of country revenue Total (Take Rate)	21.86%	20.23%	11.96%	21.65%
% average to date		21%	18%	19%
Production entitlements (Barrel)				
Average Realized Oil Price				
Total Value				
% of country revenue				
% of country revenue Remittance+Barrels	22%	20%	12%	22%
% average to date		21%	18%	19%
Ghana Revenue	$ 869	$ 667	$ 1,196	$ 1,404
YoY change	-31.7%	-23.3%	79.4%	17.4%
% of total	54%	49%	63%	63%
Remittances to government	$ 192.49	$198.81	$100.26	$ 194.55
Production Entitlements ($)				
Income Taxes & MGO Taxes		$ 27.31		$ 67.22
Royalties				
Bonus, License Fees, Infrastructure, Training	$ 4.53	$ 3.85	$ 1.67	$ 2.48
VAT	$ 3.71	$ 18.10	$ 2.75	$ 2.90
Withholding Tax	$ 63.32	$ 66.97	$ 43.39	$ 78.48
PAYE & National Insurance	$ 16.60	$ 15.39	$ 14.32	$ 17.84
Carried Interests	$ 94.11	$ 60.66	$ 14.09	$ 20.22
Customs Duties	$ 10.22	$ 6.53	$ 24.03	$ 5.40
% of country revenue Total (Take Rate)	22.15%	29.82%	8.38%	13.86%
% average to date		26%	20%	19%
Production entitlements (Barrel)	0.664	0.603	1.063	1.105
Average Realized Oil Price	$ 67.00	$ 61.40	$ 58.30	$ 68.50
Total Value	$ 44.49	$ 37.02	$ 61.97	$ 75.69
% of country revenue	5%	6%	5%	5%
% of country revenue Remittance+Barrels	27%	35%	14%	19%
% average to date		31%	25%	24%
Average Combined Take Rate (Guinea,Gabon,Ghana)	21.7%	18.8%	14.6%	14.8%

Source: WKA

Cash Flow Forecasting

As discussed in the previous section, payment transparency accounts represent direct cash outflows from the operator to the government and are not accrual-based estimates. As such, establishing how significant the outflows are, vis-à-vis Cost of Sales, Operating Cash Flow and Overall Income Taxes, can be instructive. Figure 9 highlights this common size analysis for Tullow's remittances.

Figure 9
Government Remittance Common Size Analysis

Tullow Oil	2015A	2016A	2017A	2018A
Remittance View				
%Cost of Sales [All Production Entitlements, Bonus, License Fees, Infrastructure/COS]	22.0%	22.5%	13.8%	16.9%
%Cost of Sales [All Remittances ex barrels/COS]	28.8%	25.3%	15.0%	25.0%
%Income Taxes [Reported Fiscal Regime Taxes, Royalties/IS Income]	56.1% credit	44.9% credit	84.0% credit	114.1%
%Income Tax Actual [Income Taxes, Withholding/IS Income Tax]	45.6%	33.2%	58.8%	95.2%
%Operating Cash Flow [All Remittances Ex Barrels]	29.9%	50.1%	12.4%	21.1%
%Operating Cash Flow ["All" Taxes]	14.9%	27.3%	7.6%	16.6%
%Operating Cash Flow [All Remittances+Barrels]	38%	63%	20%	30%

Source: Tullow 2018 Annual Report & WKA

As can be seen from the line "%Operating Cash Flow", the disclosed remittances as a percentage of Cash Flow from Operations varies from 12.4% to 50.1% and averages 28%. In addition, the disclosed remittances as a percentage of Cost of Sales varies from 15% to 28% and averages 23%. Tullow's Cost of Sales account represents the largest category of costs for the firm, consistent with its oil and gas peers. According to these data, about a quarter of the Cost of Sales figure is attributable to payments made to governments and therefore a strong signal that analysts should attempt to model these accounts.

Taxes

Tax remittance to foreign governments is particularly important to analysts, as these payments can represent more than half a company's total reported tax on its income statement. Bloomberg LP has begun reporting these totals with a key function on its financial terminal (ES122).[10]

Figure 10 below shows these payments for sample companies in the S&P Global Oil & Gas Index. As a percentage of trailing operating cash flow, indicated in the column "%CF", the values can range from 2% to 125%, but the mean is 40%.

Figure 10
Bloomberg ES122 "Total Taxes Paid"

Company	Country HQ	ES122 Payment	Trailing Operating	%CF
Apache	United States	$ 49	$ 3,132	2%
ExxonMobil	United States	$ 35,230	$ 29,716	119%
Hess	United States	$ 468	$ 1,642	29%
Repsol	Spain	$ 2,263	$ 4,413	51%
Sinopec	China	$ 324,925	$ 131,307	247%
Total	France	$ 18,335	$ 28,726	64%
WPX Energy	United States	$ 157	$ 1,137	14%
Canadian Natural Resources	Canada	$ 2,150	$ 7,772	28%
CNOOC	China	$ 44,000	$ 122,623	36%
Eni	Italy	$ 8,956	$ 12,992	69%
Husky Energy	Canada	$ 677	$ 3,418	20%
Lukoil	Russia	$ 995,079	$ 1,115,050	89%
Marathon Oil	United States	$ 110	$ 2,904	4%
PetroChina	China	$ 407,300	$ 325,349	125%
Shell	Netherlands	$ 8,330	$ 38,442	22%
Statoil	Norway	$ 13,400	$ 16,175	83%
Suncor Energy	Canada	$ 1,695	$ 11,157	15%
Arc Resouces	Canada	$ 164	$ 697	24%
BP	United Kingdom	$ 7,500	$ 25,770	29%
Cenovus Energy	Canada	$ 548	$ 3,031	18%
Continental Resources	United States	$ 660	$ 3,313	20%
Diamondback Energy	United States	$ 133	$ 2,265	6%
Newfield Exploration	United States	$ 64	$ 1,409	5%
QEP Resources	United States	$ 131	$ 483	27%
Tourmaline Oil	Canada	$ 123	$ 1,217	10%
Woodside	Australia	$ 668	$ 3,249	21%
BHP Billiton	Australia	$ 9,100	$ 17,871	51%
Cimarex Energy	United States	$ 356	$ 1,377	26%
EQT Corporation	United States	$ 154	$ 2,165	7%
Lundin Petroleum	Sweden	$ 63	$ 1,378	5%
Oil Search	Papua New Guinea	$ 153	$ 855	18%
Oxy	United States	$ 2,166	$ 7,866	28%
Peyto	Canada	$ 53	$ 345	15%
Sasol	South Africa	$ 0	$ 43,418	63%

Source: WKA, Bloomberg

[10] The value of these payments was highlighted in a Bloomberg Intelligence webinar for analysts conducted with the Emerging Markets Investors Alliance on March 5th, 2020

The payment transparency accounts "Income Taxes" and "Withholding Tax" are extremely volatile accounts, sometimes appearing with a zero balance, as in 2015 when costs of TEN were used to offset profits from Jubilee, or in 2018 when $67 million in costs were reported. Annual disclosures of these accounts enable a clearer understanding of when offsets are being utilized and can prime analysts for what to expect in the future. Attempts have been made to model these taxes at the project level as well, and often with some success

One effort at modeling government take rates at the project level has been the IMF's "Fiscal Analysis of Resource Industries" Methodology (FARI). According to the IMF, the initial goal was to do a "proper evaluation of fiscal regimes" but the effort eventually evolved into a "revenue forecasting tool" for IMF economists and governments to evaluate revenue streams from the extractives sector. Figure 11 highlights the calculation.

Figure 11
Fiscal Analysis of Resource Industries Methodology (Project Level)

Average Effective Tax Rate (AETR)

The AETR is the ratio of the NPV of government revenue (composed of royalty, income tax, resource rent tax, withholding taxes, and so on, as specified by the fiscal regime) to the NPV of the pre-tax net cash flows of a successful project, both calculated in discounted value. The AETR thus indicates how much revenue a fiscal regime raises and is one of the definitions of "government take."

$$AETR = \frac{NPV(Gov\ Revenue)}{NPV(Revenue - Exploration - Dev\&ReplacementCapex - Opex - Decomm)}$$

Source: IMF

The AETR provides an apples-to-apples number for comparison across regimes. Unlike the AETR, this report's take rate is not project specific but utilizes aggregate annual country remittances and compares them to the revenue associated with those outlays. This measure of government take is an annual snapshot, as opposed to the AETR's project lifetime calculation. Further work could involve aggregating existing AETR calculations and reconciling them for use as a baseline for forecasting the trajectory of essential company accounts.

Benchmarking Regimes & Risk Assessment

The value of any company metric in isolation is limited. However, that same metric over time is clearly more valuable than any single instance. In combination with many other similar company metrics the comparative value can grow. Some theorists even assert that market efficiency is predicated on cumulative comparison. This prompted the famous criticism from economist Larry Summers about "ketchup economists" who claim ketchup market efficiency by showing "that two-quart bottles of ketchup invariably sell for exactly twice as much as one-quart bottles of ketchup".[11] Summers' obvious concern is fundamental mispricing of ketchup. However, that criticism aside, every investment practitioner understands market prices are contingent on a significant degree of comparative valuation. Regarding the government remittance data discussed in this report, the question that begs to be answered is, "What if all companies were required to report these data"? Insight into this question can be gleaned from some proprietary, non-public sources of data that already exist.

Wood Mackenzie (WoodMac), a global research and consultancy group, was founded in 1923 and issued its first industry research offering in 1973, the North Sea Service oil report. At the turn of the century, after a series of ownership changes by various commercial and investment banks, including

[11] https://www.nytimes.com/2009/09/06/magazine/06Economic-t.html?_r=4&partner=rss&emc=rss&pagewanted=all

NatWest, Bankers Trust and Deutsche Bank, the firm conducted an employee-buyout and refinancing. In 2015, the company was purchased by Verisk Analytics for $2.8 billion and since then has acquired a number of important data providers, including Deloitte's "Petroleum Services Group" a specialized oil and gas consultancy with one of the premier global Exploration and Production databases, Greentech Media and MAKE, both providing databases on renewables, and PCI, a specialty chemicals analysis group.[12] Taken together, WoodMac has arguably one of the largest and most comprehensive upstream E&P datasets in the world, derived from both public and private sources and staffed by over 200 analysts and petroleum economists. WoodMac provides a "Fiscal Service" product to customers like E&P companies, banks and governments.[13] This service offers petroleum fiscal regime summaries for over 150 countries, the tracking of 750 economic metrics per fiscal system and a global fiscal terms database with each country's exploration terms and fiscal changes over time. An essential part of this service is the ability to "compare and benchmark global fiscal systems", as well as "Assess fiscal systems' response to changes in the economic environment". An African regime comparison using WoodMac's Fiscal Benchmarking Tool is shown in Figure 12.

The regime comparison is for all deep-water environments in Africa (onshore and shelf comparisons are also available, as well as Asia Pacific, Europe, Latin America, Middle East, North America, Russia & Caspian regions). The comparative calculation is Government Share as a percentage of Pre-Share Net Present Value (NPV) using a price strip between $60-66 per barrel and a 10% discount rate (all these variables can be adjusted). Although not an apples-to-apples comparison with the Take Rate metric, it's interesting to note that for Guinea, WoodMac's Government Share is 37% and this report's rolling average Total Take Rate for Guinea is 38%.

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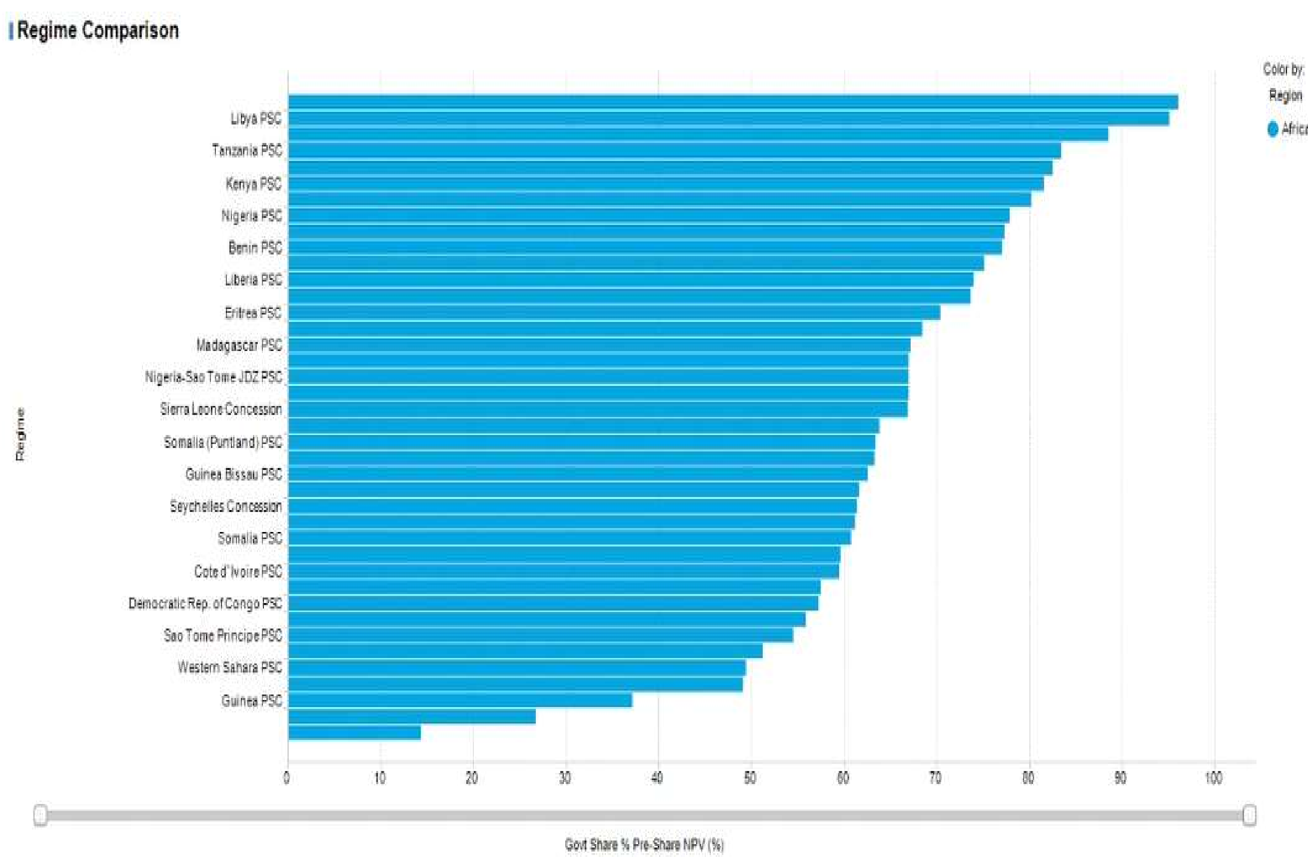
[12] WoodMac company info from: https://www.woodmac.com/about-us/ and https://en.wikipedia.org/wiki/Wood_Mackenzie

[13] A "high end" service, as it costs $31,850 per annum.

It’s important to observe that WoodMac’s Government Share is expressed as a percentage of profit, not revenue. The Take Rate calculated in this report shows government remittance without regard for the economics of taking oil out of the ground. In that way the Take Rate could theoretically be the same for projects in two different countries but with vastly different costs to the operator, if one is an unconventional project and the other a relatively cheap conventional project. The profit-based method is to take the NPV of all values received by the government and divide that figure by the pre-tax NPV of the entire project, using estimates to value the project and then summing all the projects to get to an aggregate Government Share.

Figure 12
WoodMac Fiscal Regime Benchmarking, Africa Deepwater



Source: WoodMac

The ability to properly assess government share is critical in understanding which countries have balanced their fiscal terms with prospectivity. Virtually all the regimes that occupy the top portion of the chart in Figure 10 (e.g. Tanzania, Kenya, Nigeria) have been able to impose high Government Share on operators because prospectivity is also exceptionally high. Prospectivity can be evaluated along numerous dimensions, including oil and gas volumes that have already been discovered, the overall success rate, as well as "Yet to Find" (YTF) estimates based on source rock yield or creaming curves.[14] WoodMac's variables and relative weighting scheme are shown in Figure 13 below:

Figure 13
Prospectivity Analysis

Rating	Total Volumes Discovered (mmboe)	Average Discovery Size (mmboe)	Volumes Discovered (Last 10 Years)	Exploration Well Success Rate	Yet to Find Volumes (mmboe)	% Oil in Discovered Reserves
1	No discoveries	< 1	No discoveries	0 to 5%	No YTF	< 20%
2	< 100	1 to 10	< 100	5 to 10%	< 500	20% to 40%
3	100 to 2,000	10 to 50	100 to 1,000	10 to 20%	500 to 1,000	40% to 60%
4	2,000 to 10,000	50 to 200	1,000 to 5,000	20 to 30%	1,000 to 4,000	60% to 80%
5	> 10,000	> 200	> 5,000	> 30%	> 4,000	> 80%
Weighting	**10%**	**20%**	**20%**	**20%**	**20%**	**10%**

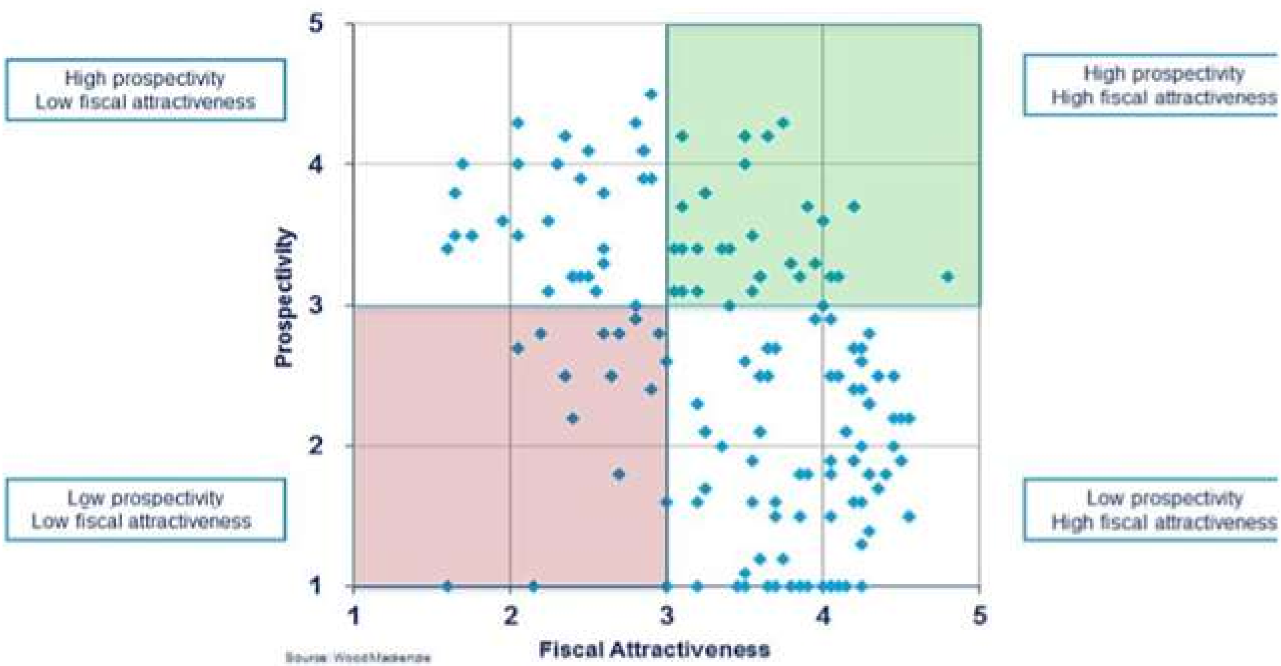
Source: WoodMac

Assuming public data were broadly available on regimes, analysts could conduct a ranking by region and then combine it with their own metrics on prospectivity for their coverage names. The results could be plotted in similar fashion to Figure 14. The ability to understand what quadrant a regime

[14] A good introduction to YTF can be found at: https://www.linkedin.com/pulse/estimating-yet-find-petroleum-exploration-alan-foum

occupies, within a regional or global context, can lend insight into the risk of fiscal changes as well as the range of upside capture for both the operator and for government.

Figure 14
Fiscal Attractiveness versus Prospectivity



Source: WoodMac

<u>Fiscal Systems</u>

In order to understand fiscal regime stability, a quick overview of the four major legal and regulatory systems used by oil and gas producing countries is warranted:

- ***Concession*** – These are generally more appropriate to developed markets and are commonly seen in North America and Western Europe. In a concession the State transfers the right to explore and produce hydrocarbons to the oil company whereby the firm takes on most of the risk and expense. The oil company owns the production and pays royalties and taxes on its revenues to the government. Royalties are typically paid at the start of operation, on either a fixed or variable basis, before costs are recovered.

- ***Production Sharing*** – Production Sharing Contracts (PSC) are signed between the host state and the operating company, whereby the two groups share the oil and gas produced. Assuming successful recovery, the company is typically allowed to recoup the costs associated with exploration and development. The remainder is shared, while the government retains ownership of the hydrocarbons. This arrangement is more common in emerging and frontier markets. Sometimes governments combine elements of PSCs with the Royalty and tax elements of Concession arrangements.
- ***Service Agreements*** – A Service Agreement is a fee-for-service (typically all costs plus a pre-determined markup) whereby the contractor takes no risk in exploration and development. The contractor does not own the production and does not have any upside gains from production. Service Agreements are seen quite frequently in the Middle East where prospectivity is very high.
- ***Joint Ventures*** – This arrangement, also referred to as participation, is utilized by countries with a designated National Oil Company (NOC) that holds the right to carry out exploration and production activities. Typically, a Special Purpose Entity (SPE) is setup whereby the government participates through the NOC's stake and hydrocarbon ownership is shared with the oil company. Venezuela is a prominent example of a country with this arrangement.

Figure 15 outlines the key distinguishing features of these arrangements, including hydrocarbon ownership, risk and levels of government involvement.

Figure 15
Comparison of Petroleum Regimes

		Concessions	Production Sharing Contracts	Service Contracts	Joint ventures
Legal	Legal & Contractual instrument	• Concession Agreement, License Agreement and Lease	• Production Sharing Contract	• Services Agreement without a risk clause	• Articles of Association, and other documents for SPE
Hydrocarbon Ownership	Hydrocarbons	• Before extraction: State • After extraction: OC (at wellhead) • OC can book reserves	• Before extraction: State • After extraction: State/OC, each proportional to its profit oil share[1] • OC can book reserves	• Before extraction: State • After extraction: State • OC paid in cash and cannot book reserves	• Production is shared between Host State and OC, proportional to their respective equity interests
Risk-reward distribution	Government compensation	• Royalties • Taxes	• Share of the State in the HC sold • Taxes	• Marketing of the HC minus Service fee • Taxes	• Portion of the profits attributable to state • Taxes
	Typical Fiscal Instruments	• Royalties • Taxation of the OC (income tax, special petroleum tax)	• Profit-oil/cost-oil split • Taxation of the OC • Sometimes also royalties	• Service fee • Taxation of the OC	• Taxation of the OC • Share of profits / dividends
	Company entitlement	• Gross production less royalty and taxes	• Cost oil/gas + profit oil/gas - taxes	• Service fee (usually fixed margin on costs / production) less taxes	• Share of produced HC profits minus taxation
	Risk taker	• OC; makes all upfront E&P investments without guaranteed returns	• OC takes exploration risk and makes all upfront investment. OC& Government share development and production costs after commerical discovery	• State; OC gets full compensation of costs and guaranteed margin	• State assumes the risk related to the percentage it holds in each business
Level of Government Involvement	Administrative and Managerial Burden	• Low; no participation in management committees. Government focuses on setting industry-wide policies	• High; government needs to attend management meetings for all the fields and take a view on all individual operatoional decisions	• Very High; government needs to plan and execute on the development of the entire oil and gas industry	• High; government has mandatory operational involvement in the fields
	Level of Control	• Low; government regulates activity of all oil and gas companies alike by setting industry standards and rules	• High: government participates in operational and investment decision making through management committees	• Very high: government decides where and how much to invest in exploration and development	• High; government has mandatory operational involvement in the fields

1. Ownership usually passes at point of export. Source: BCG analysis

Key distinguishing features

Source: The Boston Consulting Group[15]

Stability & Valuation

Under most PSCs, oil and gas companies make extraordinary investments in exploration and development, all with the expectation of reward many years after the initial outlays. One of the most important assessments a firm can make is the level of confidence in the legal promise of earning and retaining profits. Along a continuum, between the poles of nationalization and "normal" regulatory

[15] Boston Consulting Group, "Benchmarking Report", September 2012

adjustments, there is range of changes that can occur to petroleum agreements. Resource firms are acutely aware of political risk in developing countries and that sustained oil price runs, either to the upside or downside (such as experienced from 2001-2013), can exert pressure on agreements. The primary legal means for boosting confidence in fiscal stability is through stabilization clauses like the one shown in Figure 16 below.

Figure 16
Stabilization Clause Example from Azerbaijan PSA

23.2 Economic Stabilisation

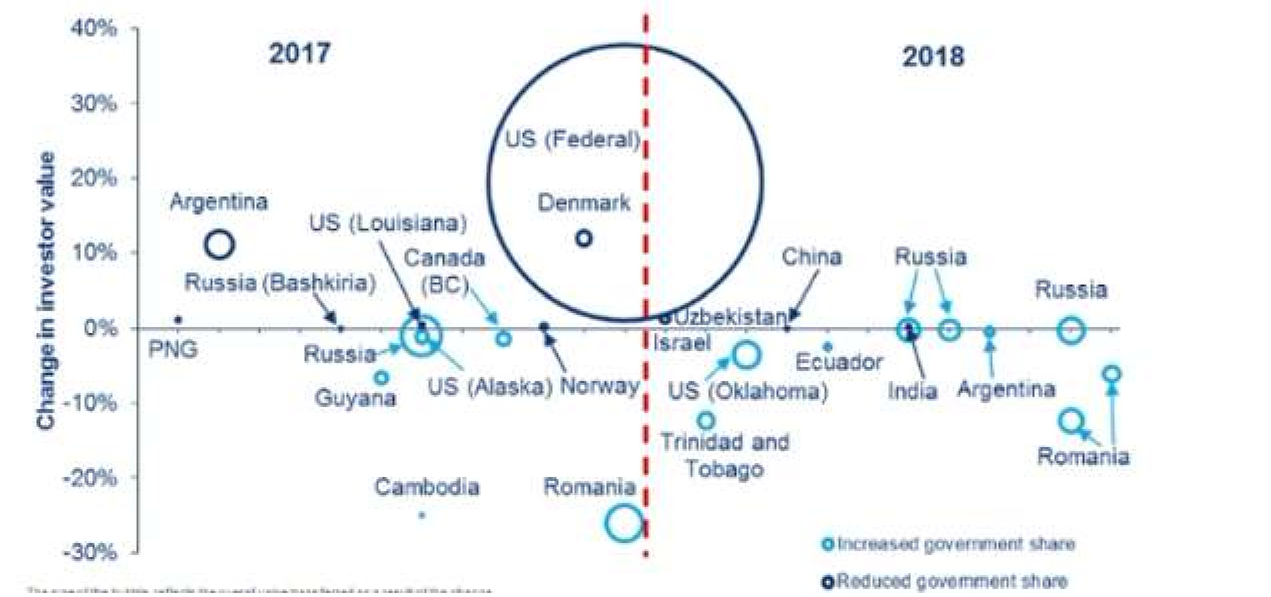
The rights and interests accruing to Contractor (or its assignees) under this Agreement and its Sub-contractors under this Agreement shall not be amended, modified or reduced without the prior consent of Contractor. In the event that any Governmental Authority invokes any present or future law, treaty, intergovernmental agreement, decree or administrative order which contravenes the provisions of this Agreement or adversely or positively affects the rights or interests of Contractor hereunder, including, but not limited to, any changes in tax legislation, regulations, or administrative practice, or jurisdictional changes pertaining to the Contract Area, the terms of this Agreement shall be adjusted to re-establish the economic equilibrium of the Parties, and if the rights or interests of Contractor have been adversely affected, then SOCAR shall indemnify Contractor (and its assignees) for any disbenefit, deterioration in economic circumstances, loss or damages that ensue therefrom. SOCAR shall within the full limits of its authority use its reasonable lawful endeavours to ensure that the appropriate Governmental Authorities will take appropriate measures to resolve promptly in accordance with the foregoing principles any conflict or anomaly between any such treaty, intergovernmental agreement, law, decree or administrative order and this Agreement.

NOTE: SOCAR is the national oil company.

Source: "Petroleum Fiscal Systems" Jarlsby, Pereira, 2018 & OnTheWorldMap.com

This form of stabilization clause is increasingly common and the essential principle that undergirds it is rebalancing in order to "re-establish the economic equilibrium of the Parties" in the event of material changes to the agreement. Accordingly, this type of clause is often referred to as the "agree to negotiate" or "economic equilibrium" clause and contrasts with "frozen law" stabilization clauses forbidding governments from making legislative changes that hurt the interests of the licensee.[16] Despite the emphasis on stability, the scope and effect of changes can differ widely from regime to regime. Some equilibrium clauses are more restrictive in terms of the type of legislative triggers and might exclude changes to environmental or occupational safety laws, while other equilibrium clauses are not symmetrical in that protection exists for regulatory changes adverse to a company's interest but regulatory benefits that improve company cash flows are not captured by the government. Figure 17 summarizes the investment[17] impact of Fiscal Disruptions in 2018.

Figure 17
Petroleum Fiscal Regime Disruptions 2018 versus 2017



Source: WoodMac

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[16] Background on stability clauses sourced from, "Petroleum Fiscal Systems" by Erik Jarlsby and Eduardo Pereira, 2018

[17] Investor Value Change = Difference in the Remaining NPV10 of all assets affected by the change / NPV10 before the change.

Looking at the twelve major changes to petroleum fiscal regimes in 2018, only two occurred in developed markets. The following is an overview of the more significant impacts from negative disruptions in developing markets (see lower right-hand corner of Figure 15):

- ***Argentina*** – Temporarily re-introduced export duties, at the higher of 12% or AR$4 per USD of exported oil or gas (in effect until yearend 2020).
- ***Ecuador*** – Increased its petroleum production tax, to albeit small effect as these are deducted before the payment of fixed service contract fees.
- ***Romania*** – Introduced new taxes on future offshore production, delaying development of these resources. The country also introduced a 2% financial contribution on gross gas revenue (technically not a fiscal measure but acts like a royalty).
- ***Russia*** – Setup a six-year program to reduce the export duty to zero and increase mineral extraction tax (MET) on all production. Net effect will be higher fuel and refinery-gate crude prices, and higher government revenue. A subsidies regime was also instituted to blunt the effect on refiners and consumers.
- ***Trinidad & Tobago*** – Introduced a 12.5% royalty to all gas and condensate production that was not under the old regime. British Petroleum's assets most affected.[18]

The influence of these disruptions on aggregate asset values can be seen quite clearly in Figure 15. As Government Share increases, a concomitant negative change in investor value occurs. However, evaluating the impact of petroleum fiscal regime changes on individual company performance can be harder to isolate, due to the inordinate impact of petroleum price changes. Figure 18 highlights

[18] Insights courtesy of WoodMac "Fiscal Stability Report 2018".

the fiscal regime changes that occurred in Ghana over the last decade, combined with an equity price chart of Tullow Oil and Brent Crude price.

Figure 18
Ghana Petroleum Fiscal Regime History & Tullow Oil

Source: Bloomberg, WoodMac and WKA Analysis

All licenses in Ghana are awarded under concession terms, governed by the 2016 Petroleum Production and Exploration Act as well as subsequent 2018 regulations. The following is a summary of the major petroleum fiscal regime milestones (Figure 20), also highlighted in the white blocks in Figure 16[19]:

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Figure 20
Ghana Petroleum Fiscal Regime Changes Timeline

Year	Fiscal Change
2018	(-) Petroleum Regulations passed. First licensing round: new Model Agreement published. AOE defined in regulations and no longer negotiable.
2016	(-) Petroleum Act passed: set government minimum participation to 15%, introduced signature and production bonuses, local content fund contributions, fixed area rentals.
2015	(-) Income Tax Act passed: petroleum income tax no longer negotiable, defined in act at 35%.
2014	(-) 6 new contracts signed: increased oil royalty to 10-12.5% from 5-7.5%, increased gas royalty to 5-10% from 3%, increased area rentals, increased training fees, introduced technical fees.
2009	(-) Successful appraisal of the play-opening Jubilee field. Contracts signed subsequently have increased government participation and royalty. General toughening of terms observed hereafter.

Source: WoodMac and WKA Analysis

The government participates in upstream licenses through the Ghana National Petroleum Company (GNPC), which by law must have an initial participating interest of 15% in each agreement (announced mid-2016). This initial interest is carried without reimbursement for exploration and development costs. As well, there is a profit tax known as the Additional Oil Entitlement (AOE), payable based on the contractor's rate of return and is non-negotiable (announced in 2018).

As can be seen in the price chart, Tullow equity largely flatlined after these two negative fiscal regime announcements, despite a rising Brent oil price environment in both circumstances (a virtual doubling from peak to trough). Even more dramatic equity price downswings occurred in 2014, after an increase in oil royalties, and in 2015 when the Income Tax Act first passed, but both movements were muddied by a steadily declining oil price. In addition, it's important to note that during this time period, confidence in the productivity of the company's assets in Ghana began to decline as operational challenges increased.

Conclusion

Payment transparency data clearly benefit securities analysts in the valuation of extractives industry companies. In addition, the investor harms associated with inadequate payment transparency are similarly clear. A simple example from recent memory highlights the point. In 2013, during the Goodluck Jonathan administration, and following years of record windfalls due to high oil prices, Nigeria's central bank governor Lamido Sanusi raised alarms when he discovered a $20 billion treasury shortfall from the Nigerian National Petroleum Company (NNPC). A 2015 audit by PriceWaterhouseCoopers (PwC) confirmed the discrepancy, which was attributed in part to the award of overly generous deals to allies of Jonathan and his oil minister Diezani Alison-Madueke. For his efforts, Sanusi was fired and no Jonathan administration officials were held accountable. On the day of the Sanusi firing, nervous investors sold-off Nigerian assets, reduced the value of the Nigerian currency by 3.2% and spiked yields on Nigeria's 10-year Eurobonds by 11 basis points. While investors soon forgot this one-time market event, the long run effect on Nigerian investment remains to this day.[20] A number of analysts have asserted that payment transparency legislation, like Canada's ESTMA regime analyzed in Appendix I, could have mitigated or prevented the harms associated with the Nigerian episode by publicly disclosing payments made under the various petroleum fiscal regimes at the time[21].

As can be seen from the analysis in this report, investors would benefit greatly from an alignment of payment transparency rules. Fruitful comparisons between companies and across transparency accounts is stymied by differing rules and inappropriate exemptions.[22]

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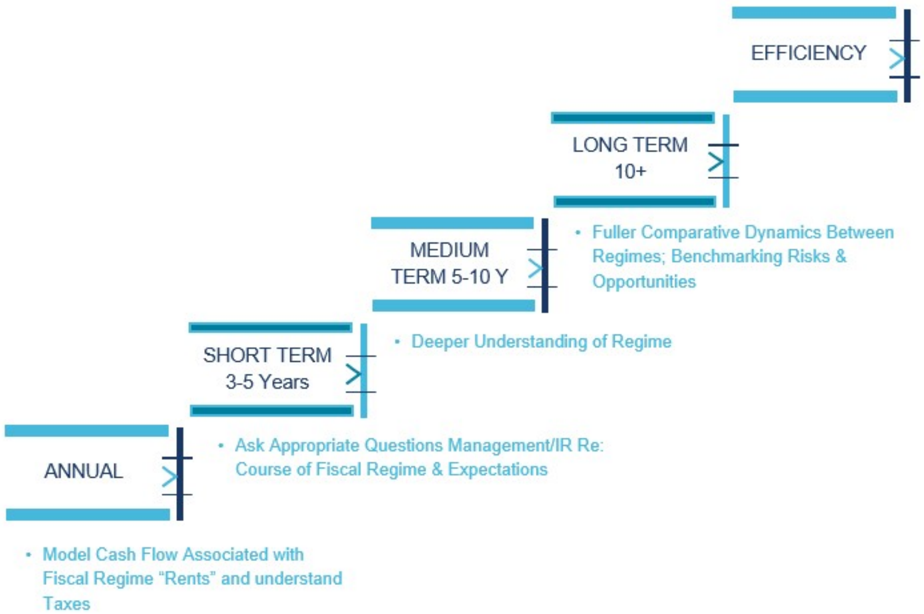
[20] https://www.pwc.com/ng/en/assets/pdf/impact-of-corruption-on-nigerias-economy.pdf

[21] Purcell Global Strategies

[22] A recent disclosure by Total SA indicated that the cost of payment transparency compliance amounted to 7 basis points on total operating costs, or $200k annually. A remarkable small number.

Figure 21
Long Run Benefits to Risk Pricing & Market Efficiency



Source: WKA Analysis

Perhaps the greatest investment benefit of payment transparency disclosure will come in the medium to long-term as data aggregate in the public domain (see Figure 21). Efficient pricing of risk is predicated on transparency. Understanding the complete cash flow history and performance of companies under various oil and gas fiscal systems will allow analysts to benchmark country and regional performance, as well as better understand the risk of changes to these regimes.

Appendix I: Additional Transparency Regimes

Extractive Sector Transparency Measures Act

The Extractive Sector Transparency Measures Act (ESTMA) was enacted by Canadian Parliament in December of 2014 but came into force six months later than similar regulation passed in the UK (cited at the beginning of this report). The Canadian Act requires businesses engaged in the extractive industry to report payments made to the government of Canada, as well as any payments made abroad. The specific requirements read that "An Entity[23] under the Act is required to report if the following conditions apply:

- The Entity or the Entity's securities are listed on a stock exchange in Canada.
- The Entity has a place of business in Canada, does business in Canada, or has assets in Canada, and meets two of the three following minimum thresholds:
    1. In one of its two most recent financial years had at least C$20 million in assets.
    2. Generated at least C$40 million in revenue.
    3. Employed an average of at least 250 employees.[24]

These security exchange and company size requirements have resulted in many public and private companies reporting government payments under ESTMA. An analysis of the first 500 filings from the 2017-2018 file period (of 775 total) yields the industry composition shown in Figure 22.

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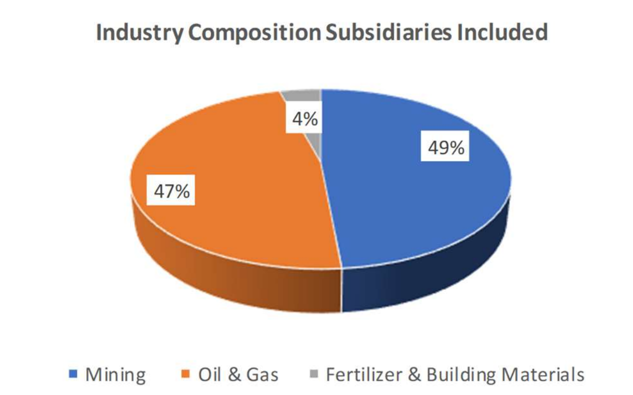
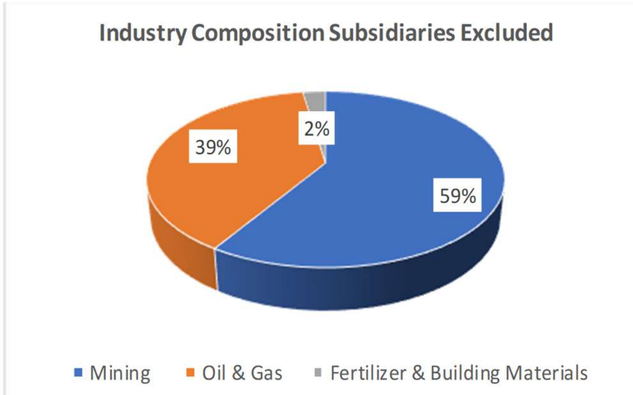
[23] An Entity under the Act is a corporation or a trust, partnership or other unincorporated organization that is engaged in the commercial development of oil, gas or minerals. This definition includes businesses that control, directly or indirectly, other Entities that engage in such activities.

[24] https://www.nrcan.gc.ca/mining-materials/estma/18802#A1

Figure 22
ESTMA Sample, Industry Composition



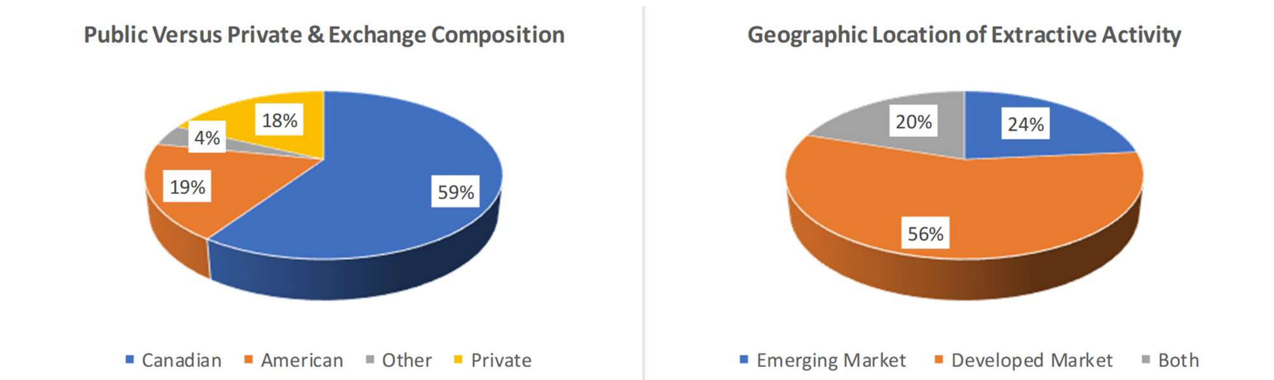


Source: WKA Analysis

As can be seen, the mining and old and gas industry dominate the disclosures. The balance, reflected in the "Other" category, belongs to companies like Nutrien (NYSE: NTR), CRH plc (LSE: CRH) and Glencore (LSE: GLEN) involved in such activities as potash mining, building materials, and commodity trading respectively. Under the Canadian Act companies are required to file for all their subsidiaries, leading to many duplicate filings (firms often chose to file the same consolidated report for all their subsidiaries). For instance, TransGlobe Energy Corporation (TSX:TGL) filed the same consolidated report for all 12 of its operating subsidiaries. The rights side of Figure 22 shows the industry composition when subsidiaries are removed from the database. This reflects the true industry make-up, with the balance shifting to the mining group at roughly 60% of the database.

Figure 23 shows the number of public versus private companies in the database, as well as the geographic location of the securities exchanges for the public companies. Understandably, given ESTMA requirements, public companies dominate at 82% of the total, as well as North American exchange-listed entities at 78%. The right side of Figure 11 shows the breakdown of the geographic location of extractive activity with developed market (DM) operations representing a sizable majority of the pure-play activity at 56%. Combined with the firms that have operations in both emerging markets (EM) and DM, the percentage leaps to 76% for overall DM activity. For the pure-play DM extractive firms, most operational activity occurs in North America (at 86%). The pure-play EM firms constitute 24% of the database (spread between mining and oil and gas).

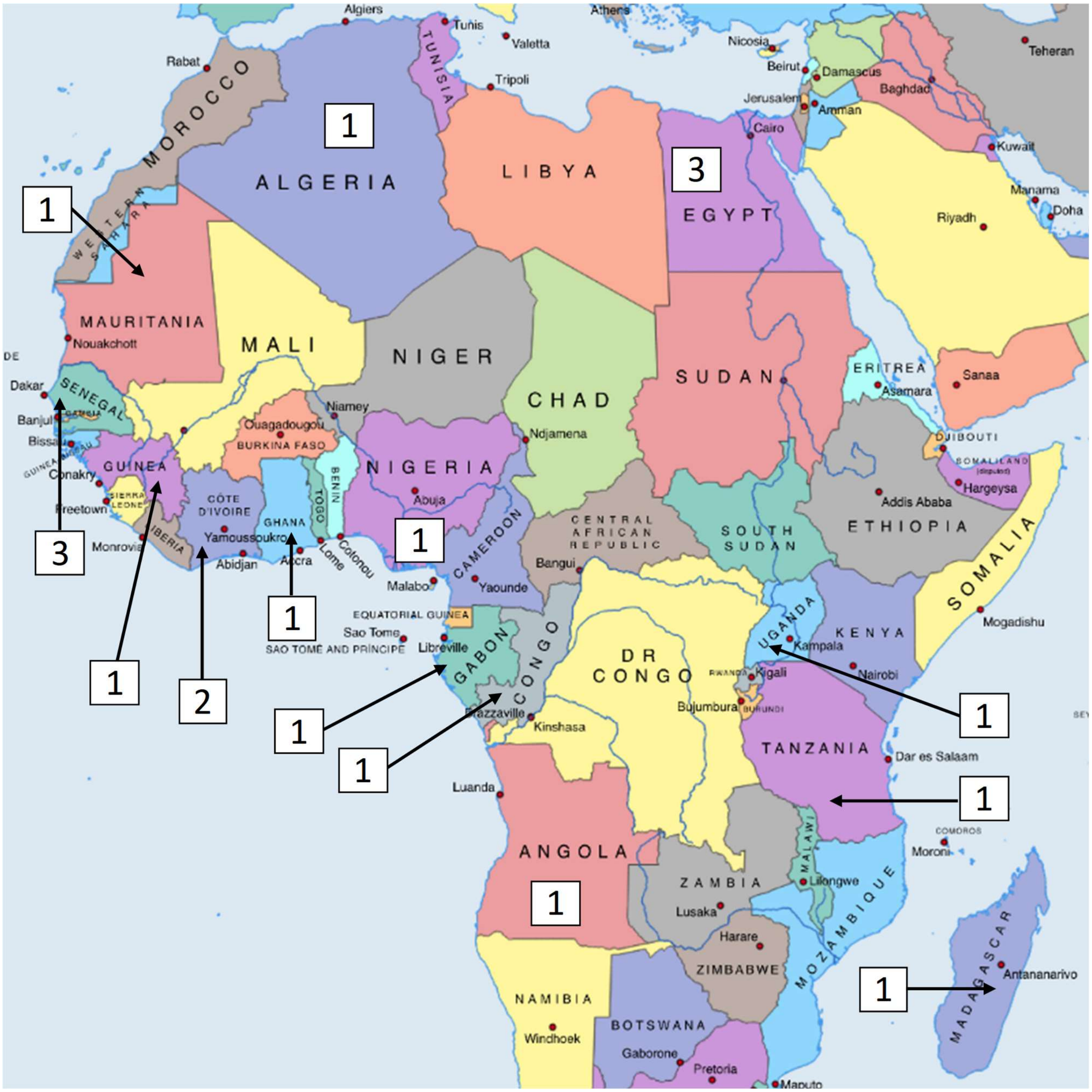
Figure 23
ESTMA Sample, Exchange Listing & Operation Location



Source: WKA Analysis

The number of Oil & Gas companies in the sample with operations in EM stood at forty-seven. Figure 24 shows the number of remittance reports for each country in Africa. For most countries there is only a single remittance report reference. This is understandable given that the sample represents only one year of reporting, and only for companies in Canada. A full benchmarking exercise will require many more years of data, and fuller participation in government remittance disclosure regimes.

Figure 24
Number of Remittance Reports for Each Country in Africa



Source: Mapswire.com & WKA Analysis