

ECLAC SUBREGIONAL
HEADQUARTERS
FOR THE CARIBBEAN

Navigating transfer pricing risk in the oil and gas sector

Essential elements
of a policy framework
for Trinidad and Tobago
and Guyana

Sheldon McLean
Don Charles
Antonio Rajkumar



UNITED NATIONS

ECLAC

Thank you for your interest in this ECLAC publication



Please register if you would like to receive information on our editorial products and activities. When you register, you may specify your particular areas of interest and you will gain access to our products in other formats.



www.cepal.org/en/publications



www.cepal.org/apps

SERIES

STUDIES AND PERSPECTIVES

101

**ECLAC SUBREGIONAL
HEADQUARTERS
FOR THE CARIBBEAN**

Navigating transfer pricing risk in the oil and gas sector

Essential elements of a policy
framework for Trinidad and Tobago
and Guyana

Sheldon McLean
Don Charles
Antonio Rajkumar



UNITED NATIONS

ECLAC

This document has been prepared by Sheldon McLean, Coordinator of the Economic Development Unit of the Economic Commission for Latin America and the Caribbean (ECLAC) subregional headquarters for the Caribbean, and Don Charles, energy consultant, with assistance from Antonio Rajkumar, individual contractor at the ECLAC subregional headquarters for the Caribbean.

The views expressed in this document, which has been reproduced without formal editing, are those of the authors and do not necessarily reflect the views of the Organization.

United Nations publication
ISSN: 1728-5445 (electronic version)
ISSN: 1727-9917 (print version)
LC/TS.2021/10/Rev.1
LC/CAR/TS.2021/3/Rev.1
Distribution: L
Copyright © United Nations, 2021
All rights reserved
Printed at United Nations, Santiago
S.21-00247

This publication should be cited as: S. McLean, D. Charles and A. Rajkumar, "Navigating transfer pricing risk in the oil and gas sector: essential elements of a policy framework for Trinidad and Tobago and Guyana", *Studies and Perspectives series-ECLAC Subregional Headquarters for the Caribbean*, No. 101 (LC/TS.2021/10/Rev.1-LC/CAR/TS.2021/3/Rev.1), Santiago, Economic Commission for Latin America and the Caribbean (ECLAC), 2021.

Applications for authorization to reproduce this work in whole or in part should be sent to the Economic Commission for Latin America and the Caribbean (ECLAC), Documents and Publications Division, publicaciones.cepal@un.org. Member States and their governmental institutions may reproduce this work without prior authorization, but are requested to mention the source and to inform ECLAC of such reproduction.

Contents

Abstract.....	7
Introduction	9
I. Hydrocarbon industry in Trinidad and Tobago and Guyana.....	13
A. Hydrocarbon industry in Trinidad and Tobago.....	13
B. Hydrocarbon industry in Guyana	15
C. The transfer pricing problem	16
II. Oil and gas global value chain	17
A. Crude oil global value chain	17
B. Natural gas global value chain.....	20
III. Oil vs gas markets and pricing	23
A. Oil markets and pricing	23
B. Natural gas regional markets and pricing	24
1. Indexation/cost plus pricing	25
2. Gas-on-gas competition	26
IV. Taxation modalities: oil and gas industries	27
A. Licenses	27
1. Concessionary system	27
2. Production sharing contracts.....	27
3. Service contracts	28
B. Taxes.....	28
1. Royalties.....	28
2. Income tax.....	28
3. Windfall taxes.....	28
4. Tax incentives.....	29
C. Fiscal regime in Guyana.....	30

D.	Fiscal regime for oil and gas in Trinidad and Tobago.....	31
E.	Tax incentives in oil and gas sector in Trinidad and Tobago.....	32
V.	Transfer pricing, base erosion and profit shifting	33
A.	How the hydrocarbon industry creates opportunities for transfer pricing risk.....	34
B.	The OECD approach to addressing transfer pricing risk.....	37
C.	Addressing transfer pricing	37
1.	Australia.....	37
2.	Colombia.....	38
3.	Ghana.....	39
4.	Greenland.....	39
5.	India	39
6.	Administrative pricing in Norway, Angola, and Indonesia.....	39
VI.	Estimated revenue loss for Trinidad and Tobago	41
A.	Estimated revenue loss in the natural gas industry	41
B.	Relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago	43
VII.	Policy recommendations	45
A.	Recommended framework.....	45
1.	Designate a revenue authority to set a fair price for the hydrocarbons	46
2.	Implementing advanced pricing agreements.....	46
3.	Establishing a reporting and monitoring framework.....	46
4.	Addressing the natural gas netback prices.....	47
VIII.	Conclusion	49
	Bibliography	51
	Annexes	
Annex 1	58
Annex 2	59
Annex 3	67
	Studies and Perspectives-The Caribbean Series: issues published.....	68
	Tables	
Table 1	Estimation of effective tax rate for Guyana under current production sharing contract	16
Table 2	Top oil exploration companies by revenue stream in 2018	18
Table 3	Top oil exporting countries	18
Table 4	Taxation of oil and gas production.....	29
Table 5	Trinidad and Tobago LNG exports to destination markets (BCM).....	36
Table A1	Summary of the OECD's BEPS action plan	58
Table A2	Descriptive statistics.....	62
Table A3	Stationary tests	63
Table A4	Structural break test for GDP.....	63
Table A5	Structural break test for GORTT energy revenue.....	64
Table A6	Dependence between the energy revenue and the GDP at the decompositions	66
Table A7	Granger causality results	66
Table A8	Estimated tax revenue.....	67

Figures

Figure 1	Trinidad and Tobago Crude oil and natural gas production, 1999-2019.....	14
Figure 2	Natural gas prices in regional markets	35
Figure 3	Estimated tax revenues under the 3 scenarios, 1999-2018	42
Figure 4	Trinidad and Tobago central government energy revenue	43
Figure A1	Wavelet decomposition for the energy revenue (Daubechies 3 levels of detail)	65
Figure A2	Wavelet decomposition for the GDP (Daubechies 3 levels of detail)	65

Diagrams

Diagram 1	Oil and gas global value chain.....	19
Diagram 2	Indexation demand and supply curves for natural gas.....	25

Abstract

Caribbean economies are increasingly grappling with the need to increase revenue generation in order to create the necessary fiscal space for financing economic recovery during the post-COVID-19 era. For energy exporting economies, optimizing natural resource rents has re-emerged as a leading policy objective with transfer pricing risk mitigation being a key modality for achieving this policy goal.

Multinational energy companies (MECs) invariably possess relatively greater institutional capacity than developing country governments and can, therefore, reduce their tax liability through the use of transfer pricing. Transfer pricing is an accounting procedure that records the financial transactions between a company and its subsidiaries and divisions and can be applied for services, intellectual property, financing, interest, and the exchange of goods. Transfer pricing risk is the chance that the transfer prices do not reflect true market prices, i.e. resulting in the shifting of a company's profit from one jurisdiction to another thereby eroding the local tax base. Guyana and Trinidad and Tobago are among the Caribbean countries with commercial reserves of hydrocarbons, where transfer pricing risk has the potential to result in considerable revenue leakage.

This study explores the oil and gas value chain by first examining the oil and gas taxation framework and assessing the mechanics of the industry's natural creation of opportunities for transfer pricing. The results of the analysis are then used to identify the most appropriate regime with which to address transfer pricing and provide sound policy recommendations for its implementation. Consequently, the study posits that inherent pricing risk can be mitigated by developing an appropriate fiscal and legislative framework complemented by the designation of a competent revenue authority to ensure that multinationals set fair hydrocarbon prices. Further research possibilities however remain, particularly by expanding the focus of the analysis to include Latin American economies and employing a game theory framework.

Introduction

Many small developing economies are fortunate to be endowed with mineral natural resources. However, more often than not these countries lack the capacity to monetize their natural resources and therefore often engage multinational companies. Fiscal incentives are frequently used as the primary tool to attract foreign direct investment in these mineral natural resource-based, particularly hydrocarbon-based, economies. Small developing economies often compete with each other for this foreign investment by offering deeper and broader incentives, which more often than not place the host country in a disadvantageous position. This scenario is often referred to as the “race-to-the-bottom” (Razin and Sadka 2012; Readhead 2018). The intuition is that when developing countries offer low taxes on their natural resources, they forego potentially significant fiscal revenue.

Multinational companies operating in the hydrocarbon industry are usually cognizant of the tax regimes prevailing in different countries. Multinational energy companies (MECs) have complex, international supply chains that contract a host of specialist companies in the process of bringing vital commodities from its source to the final market. The MECs conduct business with their subsidiaries, paying them for services, and subsequently transferring value. The process in which value is exchanged in these related party transactions is referred to as transfer pricing.

Essentially, transfer pricing is a practice where one division or affiliate of a firm may charge another division of a firm for goods and services that it may provide (Seth 2019). This is a standard practice as several firms may conduct business with their affiliates (Amidu et al. 2019). Transfer pricing risk refers to the practice where some firms have the potential to shift income to other jurisdictions and erode the local tax base. This can result from an organization engaging in multiple transactions with its affiliates, but not at an arm’s length basis. Therefore, cost is shifted from one affiliate to another, resulting in the shifting of profits and the reduction of the tax liability in the local jurisdiction (OECD 2013).

MECs have the capacity to shift value along their global value chain, which in turn can reduce their tax liability through base erosion and profit shifting (BEPS). This can result in hydrocarbon-rich countries earning less than their fair share of hydrocarbon revenues.

Shifting to a brief consideration of the magnitude of the commercial hydrocarbon reserves of two (2) subregional economies, it is noteworthy that in 2015, a well which was drilled by ExxonMobil affiliate, Esso Exploration and Production Guyana Ltd., made a commercial find of more than 295 feet (90 meters) of high-quality oil-bearing sandstone reservoirs. The well, Lisa-1, was drilled in the Stabroek Block, 190 kilometers (120 miles) off the Guyana coast (OET 2016). Following that find, ExxonMobil has made additional discoveries (OGJ 2018). ExxonMobil estimates that the Lisa wells alone could hold more than 1.4 billion recoverable barrels (bbl.) of crude oil (Krauss 2016).

Such commercial finds create prospects for Guyana to emerge as a large producer and exporter of crude oil. Even at the low price of US \$50/bbl., commercialization of the crude oil from only the Lisa fields could result in at least US \$70 billion.¹ This dwarfs Guyana's current GDP which was only US\$ 3.5 billion in 2016 (World Bank 2017).

Trinidad and Tobago also has commercial reserves of hydrocarbons. The Ryder Scott Audit 2018 revealed that in 2017, the country proven natural gas reserves were estimated at 300 billion cubic meters (bcm) (10.6 trillion cubic feet (tcf)), and produced 33.8 bcm (1.19 tcf) of gas.² Oil reserves were estimated at 200 million barrels, and oil production averaged 87,000 barrels per day (bpd) in 2018 (The Energy Year 2019).

Both Guyana and Trinidad and Tobago have multinational energy companies operating in their hydrocarbon industry. The rents accrued from the oil and natural gas sector are central to modernizing economic and developmental infrastructure, such as roads, schools, hospitals, ICT etc. Both countries are eager to attract foreign direct investment to monetize their hydrocarbons, thereby generating much needed energy rents.

Ideally, both countries should seek to capture their fair share of the generated natural resource rents. However, multinational energy companies (MECs) have greater institutional capacity than several developing country governments, and are able to reduce their tax liability through the use of transfer pricing. The prevailing problématique is whether or not (i) oil and natural gas revenue has contributed to the economic growth of resource-rich Caribbean countries; and (ii) whether energy-rich Caribbean economies are vulnerable to transfer pricing risk, i.e. have incurred significant revenue leakage due to transfer pricing by MECs.

Accordingly, the objectives of the study are to:

- explore the oil and gas value chain;
- examine the oil and gas taxation framework;
- examine the mechanics of the industry's natural creation of opportunities for transfer pricing;
- quantify where possible potential revenue losses due to transfer pricing; and
- provide policy recommendations for an appropriate regime to address transfer pricing which may be useful to Guyana, and Trinidad and Tobago.

The rest of the study is structured as follows. Section 2 reviews the energy economies of Trinidad and Tobago and Guyana as both countries are presently at different stages of their industry life cycle. Despite this, both countries are reliant upon multinational energy corporations for the development of

¹ Note, if the Government of Guyana allows international oil companies to produce and export crude oil, the government earn revenue from taxation. Such tax revenues would be less than the total export revenues. However, the US \$70 billion represents the total export revenue if 1.4 billion barrels are exported at US \$50/bbl. Additionally, in the production of oil from any well, 100% of the original oil in place (OOIP) will never be recovered. Primary, secondary and tertiary recovery methods may allow for the recovery of up to 80% of the OOIP. Energy companies typically abandon wells when it is not economical to recover the residual oil. However, for the purposes of analysis, 1.4 billion barrels is still assumed since it is expected that Guyana would be able to produce more than 1.4 billion barrels.

² This would result in a reserves-to-production ratio of 8.9 years.

the energy sector. Neither country currently has in place a robust framework to address transfer pricing and/or reduce its associated risk. Section 3 reviews the crude oil and natural gas global value chain. It is necessary to explore the oil and gas global value chain since the transfer pricing conundrum arises out of the global value chain for the hydrocarbons being controlled by the multinationals, and the governments of the host countries acting as observers rather than active players. Section 4 explains how oil and gas are priced in different markets. Section 5 explores how oil and gas are taxed. Section 6 reviews the base erosion and profit shifting. Section 7 estimates the revenue loss in the natural gas sector for Trinidad and Tobago. Section 8 provides policy recommendation to address potential transfer pricing threats and section 9 concludes the study.

I. Hydrocarbon industry in Trinidad and Tobago and Guyana

Trinidad and Tobago and Guyana are at different stages in the life-cycle of their hydrocarbon industries. Trinidad and Tobago has over 100 years of experience in the oil industry, and over 20 years of experience in the export of LNG. By comparison, commercial discoveries of oil were made offshore Guyana in 2015, and the country commenced the export of crude oil in 2020. Therefore, the Guyana hydrocarbon industry is still in its nascent stage, while that of Trinidad and Tobago's is mature.

A. Hydrocarbon industry in Trinidad and Tobago

Trinidad and Tobago gained its independence from the UK in 1962 and the country became a republic in 1976. The Government of the Republic of Trinidad and Tobago (GORTT) came to rely on the export taxes from the oil industry for revenue for public finance. This was highly advantageous as there were spikes in the oil price in 1973 and 1979, resulting in a boom in the 1970s (Campbell 2009). However, the oil price crash of the 1980s precipitated economic recession, resulting in a mass exodus of foreign energy companies³ from Trinidad and Tobago during that period (Pantin 1988; Boopsingh and McGuire 2014).

Recognizing this challenge, the GORTT sought to diversify into downstream natural gas industry to supplement revenue while building economic resilience. Until that time, natural gas had been flared off; considered a useless bi-product of oil. The government now sought to attract private sector interest in natural gas production. Notwithstanding the practical, if limited uses of natural gas in the economy at that time,⁴ private sector interest in developing the natural gas industry was anaemic. This motivated

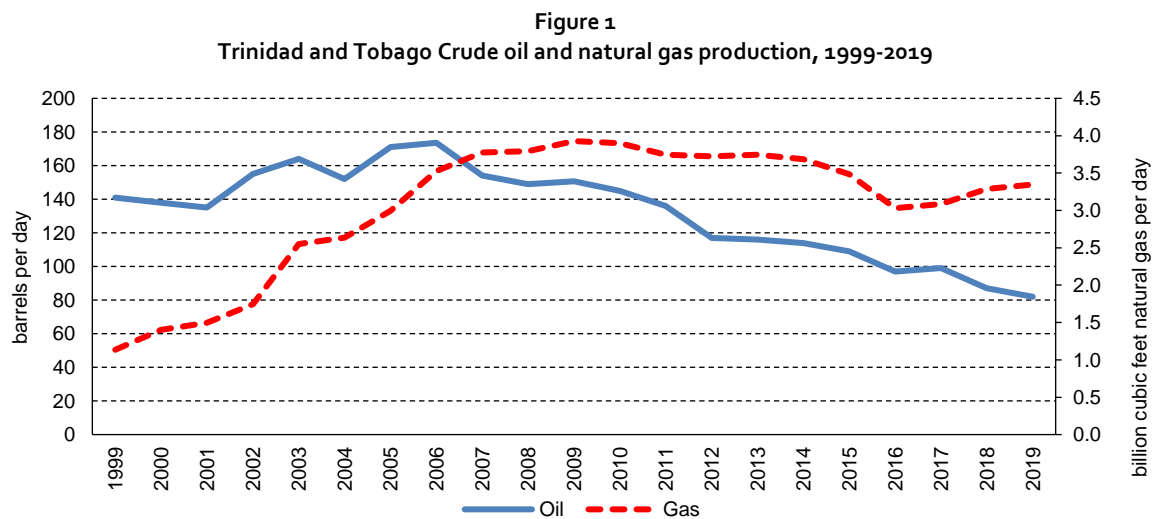
³ Some of these companies provided supporting services.

⁴ In 1953, the Trinidad and Tobago Electricity Commission (T&TEC) started to use gas for electricity generation at its Penal Power Station. Natural gas was also used for cement manufacturing by Trinidad Cement Limited (TCL), and fertilizer production by Federation Chemical Limited (Fedchem) (Jobity and Pantor 1995; Punnett and John-Toney 2001).

the GORTT to take the lead in developing the sector, the attempt at diversification into the downstream natural gas industry seen as 'questionable' at the time.⁵

Instead, the GORTT's thrust into the downstream natural gas sector proved to be an excellent shift in policy direction towards effective economic and export diversification. Currently, Trinidad and Tobago's downstream natural gas sector investment comprises 1 natural gas liquids processing facility, 4 LNG trains, 11 ammonia plants, 1 urea plant, 7 methanol plants, 1 methanol to power facility, 4 iron and steel mills, 6 power generation sites, 1 AUM complex, and over 100 natural gas intensive light manufacturing firms, including cement production (GORTT MEEI 2020). Moreover, Trinidad and Tobago has developed considerable infrastructure, labour skillset, and local companies in the energy industry over the years.

Nevertheless, the Trinidad and Tobago energy industry currently faces several structural challenges. Its oil industry is mature - all the easy discoveries have been made, both on-land and offshore, and production is declining. Therefore, in order to make new commercial discoveries, exploration companies must drill in deeper waters in the offshore blocks. As regards production, many wells have already passed the maximum production rate from primary recovery methods. Therefore, in order to maintain production levels, secondary and tertiary methods must now increasingly be employed. In fact, Trinidad and Tobago's oil production peaked in 2006 and has been on the decline since then.



Source: British Petroleum (2020), "Statistical Review of World Energy." Accessed November 2, 2020.

Natural gas production was also briefly in decline in Trinidad and Tobago. It peaked at 3.9 Bcf/d in 2010, and then went into decline until 2016. The curtailments in the natural gas industry were due to maintenance activity conducted upstream, and to delays in the renewal of upstream gas contracts.

⁵ This prompted the then Prime Minister of the Republic of Trinidad and Tobago to make the following remarks at the Sod Turning Ceremony, at the Iron and Steel Company of Trinidad and Tobago (ISCOTT) - "Blessed as we are with hydrocarbon resources, we have a choice to make. There have been attempts to persuade us that the simplest and easiest thing to do would be to sit back, export our oil, export our gas, do nothing else and just receive the revenues derived from such exports and as it were, lead a life of luxury-at least for some limited period. This, the government has completely rejected, for it amounts to putting the entire nation on the dole. Instead, we have taken what may be the more difficult road and thus accepting the challenge of entering the world of steel, aluminum, methanol, fertilizer, and petrochemicals in spite of our smallness and in spite of our existing level of technology. We have accepted the challenge of using our hydrocarbon resources in a very definite industrialization process" (cited in Charles 2019, 99).

However, this situation was addressed by the government in 2016 on its negotiation of new upstream contracts to encourage exploration and production activity (GORTT OPM 2017). Figure 1 illustrates Trinidad and Tobago's crude oil and natural gas production.

B. Hydrocarbon industry in Guyana

Guyana also has a history of exploration activity in the hydrocarbon industry, spanning over 50 years. Exploration began during the 1965 to 1975 period, when several companies drilled 9 exploratory wells. Only one resulted in oil discovery, in 1975. While this proved that oil deposits existed in Guyana, it was insufficient to motivate commercial production (Balza et al. 2020).

Oil exploration in Guyana remained sporadic over the next thirty years, with the occasional find being deemed commercially unviable. In 2008, Esso Exploration and Production Guyana Ltd. began exploration activity in the offshore blocks. This eventually resulted in successful commercial finds from 2015 (Energy Year 2019). In fact, Esso Exploration and Production Guyana Ltd. has made 16 commercial finds, pushing the proven recoverable reserves from the Stabroek block to more than 8 billion barrels of oil equivalent (boe) (Balza et al. 2020).

It is forecasted that Guyana's proven reserves in the deepwater blocks will keep growing, with increased expansion of interest in Guyana's energy industry by several multinational corporations. Exploration and production (E&P) companies have leased 9 deepwater blocks, and there has been an increasing number of foreign companies providing support services to the E&P companies (Balza et al. 2020). This is resulting in significant capital inflows, as well as in the development of infrastructure in the communities in the vicinity of the energy industry.

Guyana's oil production is expected to reach approximately 120,000 bpd at the end of 2020. This already exceeds Trinidad and Tobago's production levels which stood at 82,000 bpd in 2019. At an estimated oil price of US\$40/bbl., this approximate production level would yield a revenue of some US\$4,800,000 per day.

Certainly, the Government of Guyana is on the cusp of windfall hydrocarbon revenues.⁶ This can create growing pressure for increased public spending, subsidies and transfers, which in turn can cause a rise in the general price level (inflation), and an appreciation of the real exchange rate. Real exchange rate appreciation, in the context of an economic boom, can have destabilizing effects on an economy, a situation referred to as the Dutch Disease or resource curse (Hosein 2010).⁷

Before moving on to a consideration of the transfer pricing problem, it is important to note that the inflows calculated above represent estimated oil revenue, not profit. Taxes, however, are charged on profits. Assuming that 75% of production is cost oil, 12.5% tax through a production sharing contract, and a 2% royalty, then the eligible tax would be $0.25 \times 120,000 \times 0.145 \times \$40 = \$171,000$ (USD) per day or US\$62,415,000 per year. Therefore, the Government of Guyana's take would be \$171,000 USD per day under such assumptions.

This, however, must be set against a consideration that tax revenue will definitely increase as Guyana's oil production is projected to rise to 750,000 bpd by 2025, and to as much as 1,200,000 bpd by

⁶ There is also a possibility that Guyana may have reserves of natural gas, since natural gas deposits are often found in geological formations with crude oil deposits. This natural gas is called associated gas.

⁷ A study notes additional challenges facing Guyana: "The new economic dynamics of oil production are likely to contribute to increased migration inflows, greater electricity demand, and greater housing demand in a geographic location where around 90 per cent of the population resides in low-lying coastal areas. This introduces policy challenges for urban development, immigration policy, environmental risk management, and climate risk mitigation." (Balza et al. 2020, 7).

2030 based on primary recovery methods; the country has not yet started monetizing its natural gas; and key features of its production sharing contracts evolve over time.

It is interesting to note that under the foregoing assumptions, in a scenario where the royalty (2%) is charged before deductions for cost oil, then the Government of Guyana would derive relatively more revenue, i.e. this would result in an effective rate of tax of 5.13%. In contrast, if the cost deductions were to accrue after cost oil the effective rate of tax would be estimated at 3.56% (See table 1).

Table 1
Estimation of effective tax rate for Guyana under current production sharing contract

	Scenario 1 where the royalty is charged before costs	Scenario 2 where the royalty is charged after costs
Oil price (US\$/bbl.)	40	40
Rate of oil cost (%)	0.75	0.75
Oil production (bbl./d)	120 000	120 000
Cost oil (US\$)	90 000	90 000
Total revenue (US\$)	4 800 000	4 800 000
Royalty (2%) (US\$)	96 000	24 000
PSC (12.5%) (US\$)	150 000	147 000
Total tax for the GoG (US\$)	246 000	171 000
Total income after tax for the multinational (US\$)	4 554 000	4 629 000
Effective rate of tax (%)	5.13	3.56

Source: Economic Commission for Latin America and the Caribbean.

C. The transfer pricing problem

Although Trinidad and Tobago and Guyana are at different stages in the life cycle of their hydrocarbon sector, both countries rely heavily on multinational energy companies for the development of the industry. However, the hydrocarbon industry is a vast global value chain with interaction among several actors, at different stages, all involved in moving the commodity from ground to final market. Multinational corporations dominate hydrocarbon value chains. The interaction among the stakeholders in the global value chain creates several opportunities for value which should accrue to the hydrocarbon rich countries to be lost.⁸

Indeed, as already indicated, neither Trinidad and Tobago nor Guyana presently has a framework to address transfer pricing, or the loss of value from their hydrocarbon sector. The following three sections seek to examine in more detail the mechanics of the functioning of oil and gas value chain; and the modalities of hydrocarbon pricing and taxation. An understanding of these issues is crucial to policy makers, as it may instruct the shaping of a policy framework to address transfer pricing.

⁸ In other words, there is tremendous scope for the multinational companies to conduct transactions with their subsidiaries and affiliates which are located across different segments of the global value chain. If the multinational companies conduct transactions with their affiliates but not at the arm's length principle, then value can be shifted from one affiliate to another, and thus the hydrocarbon rich country can lose the opportunity to adequately tax its fair share of value.

II. Oil and gas global value chain

As Porter (1983) notes, there is a chain of activities, or value chain, which are required to bring a good or service from conception, through different stages of production, to the point where the final product is distributed and sold to the consumer. The oil and gas industry, like several other industries, encompasses a range of activities which jointly contribute to the transformation of the raw materials to the finished products. There is a distinct global value chain for crude oil, and one for natural gas.

A. Crude oil global value chain

The crude oil global value chain comprises three segments:

- upstream – exploration and production;
- midstream – transportation and processing; and
- downstream – marketing and distribution.

The upstream segment of the crude oil value chain begins with the identification of suitable locations to explore for hydrocarbons. Countries with proved reserves of hydrocarbons may directly proceed to develop this industry, or they may invite multinational companies to undertake this venture. Whether local or foreign, the exploration company must first obtain approvals and licenses from the government to conduct exploration activities to confirm the exact locations of oil deposits, as well as the characteristics of reservoirs. Oil companies may contract a variety of suppliers to provide auxiliary services such as seismic surveys, well drilling, mud logging, and equipment supply.

Once the deposits are confirmed, and the oil company has sufficient information on the reservoirs, they may implement a development programme to systematically drill production wells and bring the crude oil deposits to the surface. During production, multiple service contractors can also be hired, notably academic consultants such as oceanographers, geologist, mechanical, and chemical engineers, and non-technical suppliers including food caterers, cleaners, security guards, and drivers.

The top oil exploration companies are highlighted in table 2. It is noteworthy that these companies are also the dominant players in the natural gas industry. Furthermore, these companies are vertically integrated and operate in all segments of the crude oil and gas value chain.

Table 2
Top oil exploration companies by revenue stream in 2018

Company	USD billion
China Petroleum & Chemical Corporation (Sinopec)	426.00
Royal Dutch Shell	388.37
China National Petroleum Corp (CNPC)	346.00
British Petroleum (BP)	298.75
ExxonMobil	290.20
Total	209.36
Chevron	158.90
Rosneft	133.70
Lukoil	115.20
Phillips 66	111.46

Source: Offshore Technology (2018), "The World's Biggest Oil and Gas Companies." Accessed February 24, 2020. <https://www.offshore-technology.com/features/largest-oil-and-gas-companies-in-2018/>

Many developing countries endowed with commercial reserves of crude oil and gas operate in the upstream segment of the oil and gas global value chain. These countries may have the technical capacity to monetize the energy reserves for themselves. Other countries rely on foreign multinational energy companies to monetize the energy reserves. In some instances, the governments of these countries encourage multinational energy companies to form joint ventures with local companies.⁹ The top oil exporting countries are highlighted in table 3.

Table 3
Top oil exporting countries

Rank	Country/Region	Oil - exports (bbl./day)
1	Saudi Arabia	8 300 000
2	Russia	5 225 000
3	Iraq	3 800 000
4	United States	3 770 000
5	Canada	3 596 690
6	United Arab Emirates	2 296 473
7	Kuwait	2 050 030
8	Nigeria	1 979 451
9	Qatar	1 477 213
10	Angola	1 420 588

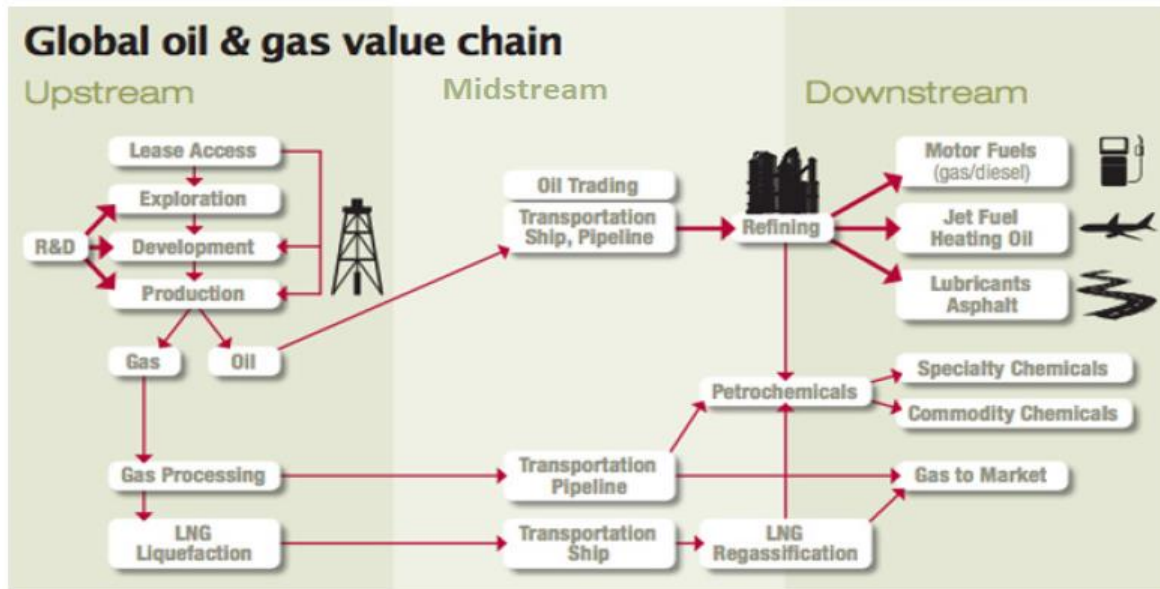
Source: (United States Energy Information Administration) (2019), "Petroleum and Other Liquids." Accessed December 14, 2019.

The midstream segment of the crude oil value chain involves transportation and processing. The crude oil is transported from the production fields, mainly through pipelines, to refineries for processing. The countries with refineries may process the oil into a variety of refinery fractions. The countries

⁹ Joint ventures are often encouraged to help capture more value locally as a local content strategy. Joint ventures are also encouraged as a means to help local stakeholder develop their capacity.

without refinery facilities may transport the oil to a facility where it is organized for export to foreign markets (See diagram 1).

Diagram 1
Oil and gas global value chain



Source: Baru, Penerbit Akademia (2019), "Logistics Management for Organizational Success of Downstream Industry in Oil & Gas."

Refining crude oil into various refinery fractions, such as heating oil, gasoline, diesel, bunker fuel, aviation fuel, etc. should be advantageous for developing countries as it allows them to capture more value added. However, there are very tight crack spreads¹⁰ in refining, and only the most efficient processors can operate profitable refineries (Fahim et al. 2009).

The downstream segment of the crude oil value chain involves the marketing, distribution and sale of the refined products. Since crude oil has varying properties,¹¹ different crude oils produce very different yields when refined. Crudes that are lighter and sweeter produce a higher refinery yield of lighter, more valuable products such as gasoline and aviation fuel, and a lower yield of lower-value products such as residual fuel oil. Refineries aspire to produce the highest yield of the high-value products to sell to markets (World Bank 2009).

The three primary refining centers in the world, which are used as benchmarks for refining margins are the United States (US) Gulf Coast, North-Western Europe, and Singapore. However, countries can sell their refinery fractions to any market, and fetch better prices and gross margins.

¹⁰ The crack spread refers to a gross margin for refining. It is the difference between the price of the crude oil, and the weighted average price of the refinery fractions. The net margin is the difference between the gross margin, and the average cost of production. If the operational cost of a refinery company is too high, it can cause a refining company's net margin to be negative (Fahim et al. 2009).

¹¹ Crude oil main properties which influences its price are its density, and its Sulphur content. The American Petroleum Institute (API) gravity determines the density and heaviness of a crude. Crudes with API gravity of greater than 10° are lighter than water and will float on water, therefore they are considered light. Crudes with API gravity of less than 10° are considered heavy (Meyer and Attanasi 2004). Light crudes are considered more valuable than heavy crudes. The Sulphur content determines the sweetness and sourness of the crude. Crudes with a Sulphur content less than 0.5% are considered sweet. Crudes with Sulphur contents in excess of 0.5% are considered sour (Wlazlowski et al. 2011). Sweet crudes are considered more valuable than sour crudes.

B. Natural gas global value chain

Like the crude oil industry, the natural gas value chain is also comprised of upstream, midstream, and downstream segments. The upstream segment of the natural gas value chain is almost identical to that of the crude oil industry. In fact, crude oil is sometimes discovered with natural gas. Natural gas found in conjunction with crude oil is referred to as associated gas. The midstream segment involves transportation and storage. The natural gas is transported from the production wells, mainly through a pipeline, to a processing facility. Dry gas, which is predominantly methane, can only be transported by pipeline (World Bank 2009). Liquid gas can be transported via pipelines or tankers, however, the liquefaction of the gas typically occurs at an export facility rather than at the well. Since extensive pipeline infrastructure is required to transport the gas, there is significant opportunity for local stakeholders to capture value from the construction of pipelines.

The downstream segment of the natural gas industry involves the processing of natural gas into various products, and the marketing and distribution of these products. At the processing facility, impurities are extracted from the gas.¹² At this stage, there are multiple options. One option is for the natural gas to be frozen at $-162\text{ }^{\circ}\text{C}$ ($-260\text{ }^{\circ}\text{F}$) to form liquefied natural gas (LNG), which can then be exported. Alternately, the natural gas can be transported to other facilities, where it can be used to produce electricity. A third option is transporting the natural gas to downstream gas companies, which in turn use the natural gas as feedstock for petrochemicals (World Bank 2015).

With respect to the latter, it is noteworthy that primary petrochemicals are divided into different groups based on their chemical structure:

- Olefins which include intermediate products such as ethylene, propylene, and butadiene. Olefins are used to produce polymers, which in turn are used to manufacture plastics, resins, fibers, elastomers, lubricants, and gels;
- Aromatics, which include intermediate products such as benzene, toluene, and xylenes. Benzene can be used to produce dyes and synthetic detergents. Olefins and aromatics are the basic building-blocks for a wide range of products including solvents, detergents, and adhesives;
- Synthesis gas, which is a mixture of carbon monoxide and hydrogen. Synthesis gas can be processed to make ammonia and methanol. Ammonia can be processed to make urea, which can be used as an input for fertilizer. Methanol can be processed to form biofuels, solvents, and antifreeze;
- Alkanes, which are highly combustible clean fuels. Methane, ethane, propane and butanes are all alkanes, and they are derived primarily from natural gas processing plants. Alkane derivatives are used in hundreds of goods, including plastics, paints, drugs, cosmetics, detergents, and insecticides; and
- Methanol and formaldehyde. Methanol can be processed into formaldehyde, which in turn is a precursor to many chemical compounds such as industrial resin, polyoxymethylene plastics, adhesives used in plywood, the wet-strength resin added to sanitary paper products (Ren et al. 2009).

Natural gas can also be transported to firms involved in gas-to-liquids (GTL) processing. GTL processing can convert methane into a range of products normally made from crude oil, such as transport fuel, naphtha,¹³ and oils for lubricants.

¹² Some of the impurities include hydrogen sulfide, carbon dioxide, water, mercury and higher-chained hydrocarbons (World Bank 2015).

¹³ Naphtha which have been produced in refineries can be catalytic cracked into aromatics.

When natural gas industries are developed downstream, a country can capture a greater share of activity from the natural gas value chain. Natural gas can also be processed to a multitude of intermediate products, which in turn can form manufacturing industries. There is great scope for the creation of backward linkages to the suppliers of raw materials and support services, and forward linkages to industries which would use the feedstock to create intermediate and final products. The formation of these linkages can also have a positive multiplier effect to generate economic activity, employment, and income earning opportunities for several nationals not directly employed in the hydrocarbon industry.

III. Oil vs gas markets and pricing

A central objective of this paper is to demonstrate that while crude oil and natural gas are both commodities similarly used as fuel in the production of electricity, crude oil markets and pricing are separate and distinct from natural gas markets and pricing. Following is an examination of their respective market and price differences.

A. Oil markets and pricing

The price of oil is generally based on the spot price of a benchmark crude oil. The main benchmarks are West Texas Intermediate (WTI), Brent and Dubai. WTI is lighter and sweeter than Brent, and is used as the benchmark for crude oil in the North American market. WTI is traded on the New York Mercantile Exchange (NYMEX) for delivery at Cushing, Oklahoma. Brent is traded on the Intercontinental Exchange (ICE) for delivery at Sullom Voe, Scotland. Dubai Crude is a medium sour crude oil extracted from Dubai and is used as a price benchmark for the Persian Gulf area.

The price of crude oil is also determined by its demand and supply. Hamilton (1983) identified several factors which influence the price of oil. In summary, the demand for crude oil is influenced by:

- The demand for its refinery fractions (gasoline, diesel, heating oil, aviation fuel, etc.).
- The weather and climate (which also influence the demand for the refinery fractions). For example, in the winter, the demand for oil should increase since more of the commodity is consumed to produce electricity for heating.
- World income, or GDP, and its growth; an increase in global income invariably results in an increase in consumption.
- The demand from major consuming countries and regions, such as the US, Europe or the Organization for Economic Co-operation and Development (OECD) bloc.

The supply of oil is determined by:

- The production quotas of major producing nations.
- The oil inventories of major producing nations.
- Wars, armed conflict, trade embargos;
- Weather disruptions; extreme weather events near to producing regions or major import hubs can cause a disruption in supply.

Other determinants of demand for oil include:

- International trade of major oil consuming countries (Chen and Hsu 2012). This can be affected but tariff and non-tariff barriers to trade.
- Demand for renewable energy, innovations in renewable energy, and the United Nations Framework Convention on Climate Change (UNFCCC) conventions on renewable energy. For example, emerging from the twenty-first Conference of the Parties (COP 21), both developed countries and developing countries agreed to submit and implement Nationally Determined Contributions (NDCs). These NDCs are voluntary renewable energy and energy efficiency plans to reduce countries CO₂ emissions (Charles 2016).

Other determinants of oil supply include:

- The US shale oil supply (Killan 2016), which can be measured by the actual supply, or by rig count.
- The flow of trade along key shipping routes (Morris 2019).

B. Natural gas regional markets and pricing

There is no one international market for gas. Natural gas is sold to different countries, each with their own distinct pricing arrangements (IEA 2012). High transportation cost of natural gas both via LNG and pipelines, has contributed to the absence of an integrated world gas market. LNG vessels costs are more than six times more expensive than oil tankers. Freight rates show similar price differences. Thus, LNG transportation costs are approximately six times more expensive than oil transportation costs (Aryanitis et al. 2012).

There are 3 major regional markets for gas (Davoust 2008; Sonstebo, 2012; Aguilera et al. 2014). They include the North American market, the European market, and the Asian market. In the North American market, the bulk of the imported gas is sourced via pipeline from Canada and Mexico to the United States. There were 12 major LNG import terminals (Sonstebo 2012), however, the US has emerged as a shale gas exporter.

The European market also has vast pipeline infrastructure (Sonstebo 2012)¹⁴ and 19 LNG import terminals to facilitate the transportation of gas (Sonstebo 2012). The European gas trade mainly takes place from Norway, Russia, and Algeria to Western Europe (Geman, 2005). In the Asian market, gas is purchased and transported as LNG (Davoust 2008; Erdos 2012). The gas is sourced predominantly from the Australia, Indonesia, the Middle East, Trinidad and Tobago, the US and Japan (Geman 2009; Erdos 2012).

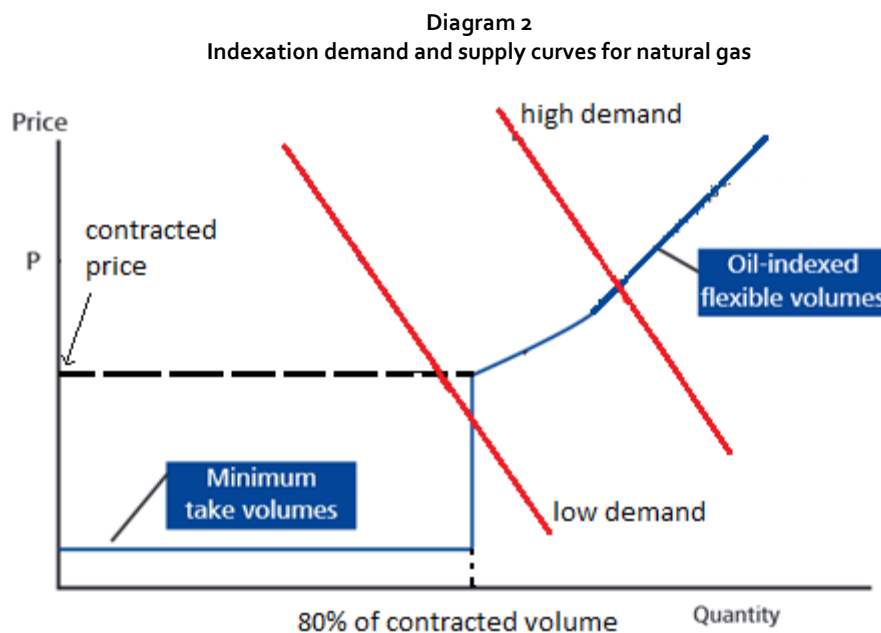
¹⁴ In 1998 a pipeline, the Interconnector, was used to physically integrate the United Kingdom (UK) with the rest of Continental Europe (Asche et al. 2012).

The imported price of natural gas traded in international markets is determined by indexation and open market/ gas-on-gas competition, which will be examined hereunder.

1. Indexation/cost plus pricing

At the inception of natural gas markets, indexation was used as the main pricing mechanism.¹⁵ With the indexation pricing formula, the price of gas was calculated as a fixed price plus an indexation to the price of a substitute fuel (e.g. oil). This resulted in the price of natural gas lagging behind the price of oil after a number of periods (often by a few months). The cost-plus pricing method¹⁶ was also a pricing mechanism used.

Natural gas contracts that were indexed to oil typically comprised two parts. The first was a minimum take volume, which was secured with a take-or-pay contract. The minimum take volume typically represented between 80% and 90% of the total contracted volume, and had a fixed price that was indexed to oil. The second part was a flexible volume which was not restricted via a take-or-pay contract. The price on the flexible volume was allowed to move based on demand and supply conditions as seen in diagram 2 (DCES 2013).



Source: Deloitte Center for Energy Solutions (DCES) (2013), "Exporting the American Renaissance Global impacts of LNG exports from the United States." Accessed June 14, 2014.

The pricing of gas in the Asian market also followed the indexation pricing structure (Melling 2010). Historically, the Asian gas market was dominated by long term contracts. However, the rise in the US shale gas has induced many importers to switch to short term contracts.

¹⁵ The natural gas indexation to oil pricing methodology was developed initially in Europe in the 1960s (Melling 2010).

¹⁶ Cost plus pricing formula is one where the price of gas at the market is equal to the well head price plus all other costs incurred at different segments of the value chain. It is the well head price plus transportation costs, plus distribution costs, plus distributor's mark up, plus taxation costs.

The benchmark used for the Asian market is Japanese LNG import prices or the Platts' Japan-Korea Marker (JKM) (Marcke 2013). Japanese and Korean prices are used as the benchmark because their LNG imports represent the bulk of the LNG imports in the Asian market (van Marcke 2013; Cunningham 2014).

2. Gas-on-gas competition

In gas to gas competition the price of natural gas is determined by its demand and supply. Natural gas trading hubs tend to develop at locations where there are both intersections of major pipelines and large storage capacities. The North American market for gas follows the free market pricing structure. The major reference point for gas prices in the US is the Henry Hub (HH).¹⁷ To a lesser extent, there is some degree of gas-on-gas competition in Europe, with major hubs including Zeebrugge in Belgium, National Balancing Point (NBP) in the United Kingdom (UK), and Emden in Germany.

To a lesser extent, a South-American natural gas market is emerging. South American LNG importing countries; Argentina, Brazil, and Chile, compete internationally with LNG importing giants such as Japan and South Korea for their supply of spot LNG. Spot LNG tend to flow to destinations where the netbacks are the highest (Maxwell and Zhu 2011).¹⁸ In order for the South American countries to secure their spot LNG supply they need to offer the minimum price at a reference Hub (HH or NBP depending on the seller) plus a premium to account for transportation costs (Barroso, et al. 2008). It is for this reason that South American countries pay prices similar to the Asian-Pacific market for spot LNG (BAH 2013).

¹⁷ Henry Hub is a physical location in Louisiana, United States, which serves as a distribution hub for imported gas. It interconnects with nine interstates and four intrastate pipelines. Henry Hub was a good benchmark for US gas prices as it was the source point for imported gas.

¹⁸ Netback pricing is a pricing arrangement whereby the price of gas is calculated from the market back to the well head. The costs incurred at different stages at the value chain, e.g. regasification costs, shipping costs, export taxes (if any) and liquefaction costs, are deducted from the market price of gas to derive gas prices at the well head (Maxwell and Zhu 2011).

IV. Taxation modalities: oil and gas industries

Companies require approval from the state, the owner of the natural resources, to conduct exploration and production activities in a country. Governments create fiscal regimes comprised of licenses, and taxation systems. Given that projects are expected to last decades, and risks shift over different project phases, investors benefit from developing and maintaining a positive long-term relationship with the country. Ideally, governments develop fiscal terms, which invariably include the awarding of licenses, and the imposition of taxes, in an attempt to delicately balance the dual, and sometimes conflicting policy objectives of optimizing resource rents and stimulating investment.

A. Licenses

Hydrocarbon companies are guided by petroleum licenses and contracts for the extraction and monetization of attendant resources. The main types of contract systems used in the hydrocarbon sector include concessionary, production sharing and service contracts respectively. A closer examination of these follows below.

1. Concessionary system

Under this system, the energy company obtains a lease from the government for a fixed period of time and is responsible for undergoing exploration and production activities. The licensee owns their investment in the hydrocarbon rich country, and is liable to pay the government royalties, a specific petroleum tax as well as the general corporate tax. Upon the expiration of the license, the ownership of the investment is transferred to the government. The concessionary system was the only petroleum contracting system available before the 1960s (World Bank 2009).

2. Production sharing contracts

Under this arrangement, ownership of the hydrocarbon reserves and production remains with the state, however, an exploration and production company may be granted licenses and approval to conduct exploration and production activities. The licensed company funds the exploration and production

activities. However, when oil is extracted and sold, the company is reimbursed through a specified part of the production referred to as "cost oil", while the remaining output, referred to as "profit oil", is divided between the licensed company and the state, based on their share of equity. Alternately, the government may get its share of profit oil by charging a series of taxes on the profit oil (World Bank 2009).

3. Service contracts

Under this arrangement, the licensed exploration and production company is paid a fee to extract and sell the hydrocarbons for the government. There are different types of fees which can be paid to the contracted exploration and production company. These include: 1) a fixed fee per barrel produced; 2) a fixed fee as a percentage of costs; and 3) a variable fee as a percentage of gross revenues. Under all 3 constructs the contracted company finances exploration and production, however, the revenue from the successful finds are used to reimburse the company for its costs (World Bank 2009).

B. Taxes

Taxing the oil and gas sector involves a combination of fiscal measures. The most common taxes include royalties, income tax, and tax on extra or windfall income (EY 2018). Some countries also charge minor taxes on the oil and gas sector, such as a withholding tax, which is less than 5% of the total tax revenue. Hydrocarbon companies are also often offered tax incentives to encourage investment. A brief examination of the various taxes generally applied in the oil and gas sector will be undertaken hereunder.

1. Royalties

Royalties are taxes imposed on hydrocarbons to ensure that the government receives at least a minimum payment from the resource extraction. Royalties may take two forms. The first variation is specific levy, which charges taxes based on the volume of oil and gas extracted. The second is an *ad valorem* levy, which is based on the value of oil and gas extracted. *Ad valorem* royalties are very common as they can be applied to the market price of crude oil or natural gas (Sunley et al. 2002).

2. Income tax

Income tax is often imposed on oil and gas companies in addition to royalties. It is not unusual for the income tax rate applicable to oil and gas companies to be higher than non-energy companies in energy rich countries (Sunley et al. 2002).

3. Windfall taxes

In an attempt earn additional rent, especially when oil and gas prices are bullish, many governments structure the fiscal regime to include windfall taxes. Windfall taxes are *ad valorem* levies, which only apply when the hydrocarbon company earns additional revenue from favorable market conditions (Sunley et al. 2002). They can be applied to the price of the commodity. For example, a country can charge a windfall tax on oil when the price of oil rises above a specified trigger-price e.g. US \$70/ bbl. When this occurs, the government receive the additional tax revenue. Conversely, when the price of oil is below the trigger-price of US \$70/ bbl., the company would not be liable to pay the windfall tax.

Conceptually, a windfall tax has strong economic features. A properly designed windfall tax allows a government to capture an increased share of the natural resource rent, which is the return over and above the company's opportunity cost of capital. In order for windfall taxes to work properly they however must be ring-fenced. That is, costs incurred in one area should not be used to offset the windfall tax payments (Sunley et al. 2002). It is noteworthy that when designing the windfall tax, if the trigger price for the windfall tax is set too high, the windfall tax may never apply. In contrast, if the trigger price is set too low, multinational energy companies may not be amenable. Given that multinational energy

companies dominate oil and gas value chains, and therefore often have greater negotiating power than individual governments, particularly in developing economies, low trigger prices may discourage investment by the multinational companies.

4. Tax incentives

It is noteworthy that many developing countries compete against each other to attract foreign direct investment for their hydrocarbon industry. Therefore, if countries charge taxes that are high, foreign investors may be inclined to take their investment to lower tax jurisdictions. In fact, countries whose oil and gas industry are mature, or have reached a stage where there is increased risk in extracting the hydrocarbon resources may be induced to lower their taxes or offer incentives in order to facilitate the development of marginal fields.

Common tax incentives offered include capital allowances, tax reliefs for export processing zones, and reliefs for special economic zones (Maina 2019). Many countries incentivize exploration by allowing exploration costs to be recovered immediately and allowing accelerated recovery of development costs, for example, over five years. This accelerated cost recovery incentive shortens the payback period for the investor, making projects more attractive. Table 4 highlights the types of taxes applied to the oil and gas industry in select countries.

Table 4
Taxation of oil and gas production^a

Country	Royalties ^b	Income tax ^c	Windfall tax
Algeria	12.5%-20%	38%	5%-50% when oil rises above \$30
Angola		Petroleum income tax (PIT)-50%; PIT for LNG – 35%	Petroleum production tax (PPT) - 20% Petroleum transaction tax (PTT) - 70% Surface fee - US\$0.15 per bbl.
Argentina	12%	25%	
Australia	10% - 12.50%	30%	40%
Azerbaijan	No royalties. PSC ranging between 20% to 32%. Host government agreement (HGA) tax on the profitable trade of machinery -27%.		
Bahrain		46%	
Brazil	5%-10%	34%	20% to 40% based on volume
Canada	45%	15%	Tier 1 LNG tax of 1.5% to an LNG taxpayer's net operating income. Tier 2 LNG tax of 3.5% net operating income.
Chad	Oil 14.25%- 16.5%. Gas 5%-10%	35%	
Côte d'Ivoire		25%	PSC on oil volume 40%-60%.
Congo	8%-12.5%		PSC on oil volume 35%-45%
Ecuador	12.5%-18.5%	25%	Sovereignty margin — 25% of gross income of the field oil production
Germany	05-40% for oil and gas	22.8%-34%for oil and gas	
Ghana	3%-12.5% for oil and gas	35% upstream, 25% downstream	
India	oil-12.5% gas-10% Coal bed methane-10%	PSC under the Hydrocarbon Exploration Licensing Policy (HELP). Income tax 40% for foreign firms, 25%-35% for domestic.	
Indonesia		Corporate income tax (CIT)-25% Branch profits tax (BPT)-20%	
Kazakhstan		CIT-20%	Mineral extraction tax (MET)-rates based on volume. Excess profit tax (EPT)-10%-60%

Country	Royalties ^b	Income tax ^c	Windfall tax
Kuwait	15%	15%	
Libya	16.67% in PSCs. Charged on volume	20%	
Malaysia	10% of gross production	Petroleum income tax-38%	No windfall tax. But withholding tax is charged: Interest — 15% movable property — 10% Payments to nonresident contractors — 13%
Mexico	7.5% oil <\$47.95 A formula when oil >\$47.95 Gas royalty is a formula based on price	CIT-30%, PSC, Service contracts, Strong local content requirements	companies must be Mexican, be residents in the country. Withholding tax of 10% on dividends
Nigeria	0% to 20%	Petroleum Profits Tax Act (PPTA)-65.75%-85%, PSCs	Windfall tax based on km ² of acreage in the license
Norway		23%, PSCs	55% on the net operating profits
Oman		CIT-55%, PSCs	
Qatar	Rates stated in development and fiscal agreements (DFAs)	CIT-35%-55%, PSCs, oil service companies-10%	No windfall tax. Withholding tax of 7% on interest

Source: Ernst and Young (2018), "Global Oil and Gas Tax Guide." Accessed February 25, 2020. [https://www.ey.com/Publication/vwLUAssets/ey-global-oil-and-gas-tax-guide/\\$FILE/ey-global-oil-and-gas-tax-guide.pdf](https://www.ey.com/Publication/vwLUAssets/ey-global-oil-and-gas-tax-guide/$FILE/ey-global-oil-and-gas-tax-guide.pdf).

^a The data applies to oil. Where the data is applied to gas, it is clearly specified.

^b Royalties are charged on the reference price of oil or gas.

^c Income tax is charged on gross profit.

C. Fiscal regime in Guyana

Companies involved in activities in the upstream segment of the oil value chain in Guyana are governed by the Petroleum Act, the Petroleum (Production) Act, Petroleum (Exploration and Production) Act, Maritime Zones Act, Income Tax Act (ITA) and Corporation Tax Act (CTA).

Officially the fiscal regime for companies operating in Guyana's hydrocarbon industry is as follows:

- Companies involved in exploration and production activity must obtain a license.
- Any royalties charged would be specified in production sharing contracts.
- Commercial companies are taxed at the rate of 40% of chargeable income or 2% of turnover, whichever is lower.
- Companies engaged in both commercial and non-commercial activities are taxed at 40% of their chargeable income on their commercial activities, and 27.5% of their chargeable income on their non-commercial activities.¹⁹
- Companies operating in Guyana must pay corporation tax on profits, which in turn is due or before 30 April of the year following the year of income. After the first payment, taxes are due to be paid quarterly on 15 March, 15 June, 15 September and 15 December each year.
- Capital gains on assets is governed by the Capital Gains Tax Act and is payable at the rate of 20% on the net chargeable gain.
- Withholding tax is levied at source of transactions for payments made to non-residents of Guyana. The withholding tax rate is 20%.

¹⁹ This is the corporation tax rate.

- Non-resident companies are charged a withholding tax of 10%.
- Any branch of a non-resident company is charged a withholding tax of 20% on transactions conducted with resident firms or individuals in Guyana (EY 2018).

Notably, the Government of Guyana has a production sharing contract with the exploration and production companies operating upstream;²⁰ the key elements of the model are outlined and discussed below.

From the total production of crude oil per calendar month, 75 % of the aggregate value of sale will be dedicated to recovery costs by the exploration and production companies. The remaining 25% is shared 50/50 between the Government of Guyana and the exploration and production company. Therefore, the 50 % profit sharing model actually allows for 12.5% of the aggregate value of production being sold to accrue to the Government of Guyana.

There are several inherent weaknesses of this model, which compromise the ability of the Government of Guyana to capture its fair share of the oil rents. For instance, Article 11.9 of the PSC allows the exploration and production company to use as much of the production as may reasonably be required for operations. This operating cost oil is excluded from the taxable oil. For if for example 4 million barrels of oil were produced in a particular month and 1 million barrels were used for operations, then 75% aggregate value will be applied to the 3 million barrels, leaving only 0.75 million barrels to be shared 50/50 between the government and the oil company. In fact, in this example, the government share would only be only 0.375 million barrels.

Article 13 of the PSC states that value of the oil or gas used for the tax purposes should be the value of the oil and gas in the said production month. This is also flawed since oil and gas prices are volatile. The monthly price of oil or gas is the closing price for the last day of the month. However, within any month prices will often fluctuate. Therefore, the official monthly price can be lower than the actual price that the exploration and production operator actually receives. Consider another scenario, if the price of the hydrocarbon (oil or gas) was low during the production month, the exploration and production company can wait until the price reaches a higher level in future months to sell the oil. Therefore, they will be paying a tax on a lower price than at which the oil was sold.

In addition to the 12.5% effective revenue under the PSC, the exploration and production company is entitled to pay the Government of Guyana a 2% royalty. However, under Article 15, the exploration and production company is exempted from paying value added tax, excise tax, import duty, and other import fees. Furthermore, with respect to corporate tax, the Government of Guyana is required to remit the corporate tax on the behalf of the exploration and production company to the Guyana Revenue Authority. Therefore, exploration and production companies are effectively exempted from paying corporate tax.

D. Fiscal regime for oil and gas in Trinidad and Tobago

Companies operating in the exploration and production segment of Trinidad and Tobago's hydrocarbon industry are governed by the Petroleum Taxes Act (PTA).

Trinidad and Tobago's oil industry taxes include:

- A Royalty of 12.5% that is charged on the oil price;

²⁰ The companies covered by the PSC include Esso Exploration and Production Guyana Limited, Cnooc Nexen Petroleum Guyana Limited, and Hess Guyana Exploration Limited.

- A Supplemental Petroleum Tax (SPT) of 18% for land production, and 33% for marine production. SPT is only charged if the price of oil exceeds US \$50/bbl. The formula for SPT is given by:

$$SPT_{land} = 0.18(oil\ price - royalty) \times oil\ production \quad (01)$$

$$SPT_{marine} = 0.33(oil\ price - royalty) \times oil\ production \quad (02)$$

- A Petroleum Profits Tax (PPT) and an Unemployment Levy (UL) which are charged after SPT. The PPT is 50% on the remaining taxable income, while the Unemployment Levy is 5% on the remaining taxable income. This is given by:

$$PPT \ \& \ UL = 0.55(EBIT^{21} - royalty - SPT) \quad (03)$$

- A Green Fund Levy (GFL) which is charged at 0.3% of gross revenue. The Petroleum Tax Act also mandates companies to pay the Petroleum Impost which is used to cover the administrative costs of the Ministry of Energy.

The natural gas industry is subject to the corporation tax rate.²² In fact, companies involved in the business of manufacturing petrochemicals, liquefying natural gas, and the transmission of natural gas are liable to pay a corporation tax at the rate of 35% on chargeable profits (EY 2018).

E. Tax incentives in oil and gas sector in Trinidad and Tobago

Trinidad and Tobago offers a series of allowances and incentives in its hydrocarbon sector. They include the workover allowance, the dry-hole allowance, the tangible drilling costs allowance, the intangible drilling costs allowance, and the deep-water exploration allowance.

- The workover allowance provides for the deduction of costs incurred for work overs, maintenance or repair works on completed wells. The workover costs must be reviewed and approved by the Ministry of Energy.
- The dry-hole allowance provides for a deduction for the costs and the losses incurred in the drilling of dry-holes.²³ This allowance can only be claimed in the year that the dry-hole was drilled, and it must be verified by the Ministry of Energy.
- The tangible drilling costs allowance allows a deduction for costs incurred in drilling such as machinery costs, import duty, and installation costs.
- The intangible drilling costs allowance allows a deduction for intangible drilling costs. These costs include all the costs incurred in searching for hydrocarbon deposits. These costs must also be verified by the Ministry of Energy in order for the allowance to be claimed.
- In 2014, the GORTT introduced a new allowance to incentivize drilling in the deep-water blocs. This allowance allowed for the writing of 100% of the exploration costs incurred in deep-water blocs. This allowance was effective over the period January 1, 2014 to December 31, 2017.

The government has also instituted a facility (incentive) where allowances and losses that cannot be fully offset against income and the PPT for the same year may be carried forward and offset against income and the PPT in succeeding years, without restriction.

²¹ EBIT denotes Earnings before interest and taxes.

²² The corporate tax rate for non-energy companies is 30% on chargeable income.

²³ A dry-hole is a well that was drilled by an operator that does not have a commercial find.

V. Transfer pricing, base erosion and profit shifting

The practice of transfer pricing, as well as base erosion and profit shifting in the global energy sector can lead to a reduction in the resource rents that accrue to small resource-rich developing countries. In such circumstances, it may be useful to mitigate the risk through appropriate policy-setting. This, however, first necessitates an understanding of the nuances of the practice. As mentioned earlier, transfer pricing is an accounting procedure in which a company records the financial transactions between its subsidiaries or divisions. Since the subsidiaries or divisions all share a common ownership, transfer pricing reflects the recording of intra-company financial transactions. Alternately expressed, it is the recording of the transactions within a company.

A transfer price is the price that one division of a company charges another division of the same company. Transfer pricing can be applied for services, intellectual property, financing, interest, and the exchange of goods.²⁴ Transfer pricing risk represents the chance that the transfer prices do not reflect true market prices, resulting in the shifting of a company's profit from one jurisdiction to another.

It is well known in microeconomics that firms conduct business to make profit. Profit can be maximized by maximizing total revenue and minimizing total costs. Since taxes represent an expense, the minimization of taxes can facilitate achieving the profit maximizing objective. This serves as motivation for profit maximizing firms to try to minimize or reduce their taxation liability.

Since different countries have different effective tax rates, multinational firms can reduce their worldwide tax payments by shifting income from highly taxed jurisdictions to more lightly taxed locations. While profit shifting can be achieved through the reallocation of real activities, it can also be accomplished through the manipulation of transfer prices (Swenson 2000). Transfer pricing risk can occur through two avenues: (i) undercharging for transactions between divisions of a company; and (ii) overcharging for transactions between divisions of a company.

²⁴ Here the goods include raw materials, intermediate products, capital machinery, and finished products.

A. How the hydrocarbon industry creates opportunities for transfer pricing risk

The venture of exploring and producing hydrocarbons is typically carried out by multiple parties, each that has some interest in the asset. Some of the parties involved in the industry are unrelated, and have different contractual relationships, such as joint operating agreements, production sharing contracts, concessions, licenses, lease participation agreements, and services agreements.

Consider an example. A hypothetical firm that won a license from the government and is interested in exploring and producing in a deep-water bloc oil may contract petroleum geologists and geophysicists as consultants to assess some drawings with geological formations. After geological formations are confirmed, and sufficient data is collected about the probability of hydrocarbon deposits residing in certain areas, the firm may proceed to undertake drilling activities. The firm may have the internal capacity and equipment to undertake exploration drilling, but it may contract a service company to provide corrosion testing, and another company to provide bunkering services. When the hydrocarbons deposits are confirmed as proved reserves, and the company has decided to develop a platform for production, it may contract a platform fabrication company to provide the services. The company may choose to transport the hydrocarbons to shore by pipeline and may contract a pipeline fabrication company to provide these services. The company may opt to use some measure of debt financing to fund its pipeline project and in so doing obtain a loan from a financial institution.

In this simple hypothetical example, the actors include the exploration and production firm, the consultants, the corrosion testing firm, the bunkering firm, the platform fabrication firm, the pipeline fabrication firm, and the financial institution.

Assume that the different players are taxed differently. For example, the exploration and production company may have a royalty of 10%, an income tax of 30%, and a windfall tax of 40% applicable on profit oil and offshore volumes only when the price of oil is above \$65/bbl. The consultants and the service companies may only be liable an income tax of 25%. The financial institution may be located in a low tax haven with a 10% effective tax rate, and not subjected to local taxes.

Assume that the price of oil rises from \$50/bbl. to \$66/bbl. Under these conditions, the exploration firm would be liable to pay royalties, income tax on profit oil, and windfall tax on profit oil. If the exploration and production company is a subsidiary of a vertically integrated company which has other subsidiaries that can provide each of the required services, the company would have several opportunities to reduce its taxation liability. The exploration firm could therefore pay high fees for the consultant and the other services from the service companies. This would increase the cost oil and reduce the profit oil. This in turn would reduce the taxable base for both the income tax and the windfall tax. The same result can be achieved if the financing division of the company charged the exploration division a high interest rate, as well as high fees for the loan.

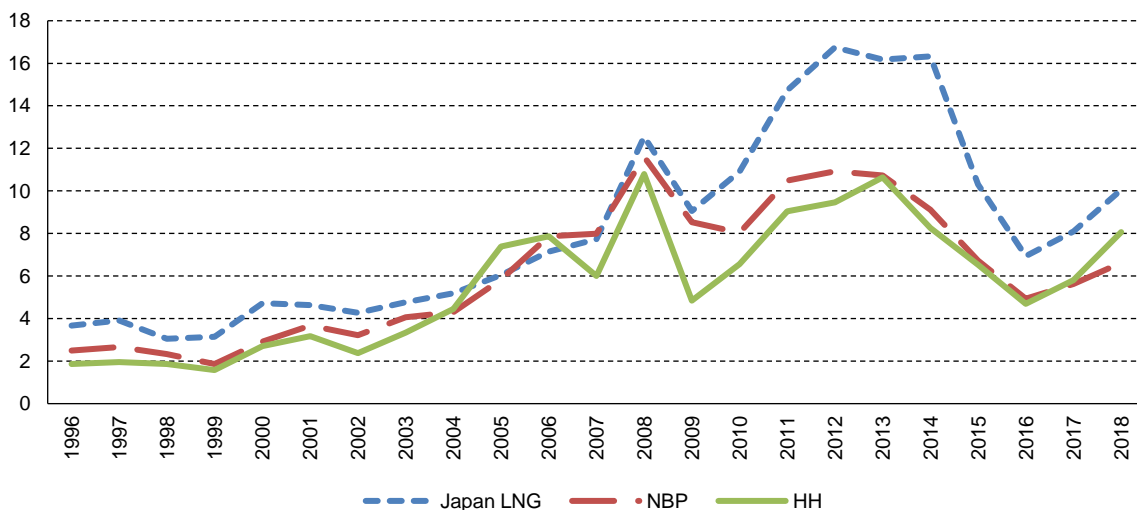
There are many actors involved in the oil and gas value chain. Vertically integrated multinational companies often have several subsidiaries which can provide supporting services. When these divisions conduct business among themselves, there are many opportunities to either overcharge or undercharge for services. The company can also charge for unnecessary services, to alter the accounting of its costs and profits in order to manipulate its taxation liability. Indeed, consultancy fees, management costs, depreciation, transfer of assets, service company fees and interest are all cost items used to manipulate the taxable income of firms.

Consider another example. Assume a hypothetical oil company has a royalty of 10%, an income tax of 30%, and a windfall tax of 40% applicable on profit oil upstream. However, in the down-stream it may be liable to pay only an income tax of 30%. If the company is vertically integrated, it can reduce its taxation

liability if its exploration division sells the oil to its refining division below costs price. Since taxes are paid on profit oil, its taxes in the upstream can drop to zero if the company declares no profit upstream. The profit could be declared in the down-stream refining division, allowing the entity to rightfully pay the government the applicable 30% income tax, while also evading the royalty and the windfall tax. Undeniably, in countries where there are different tax rates across the value chain, there is opportunity for vertically integrated firms to reduce their taxation liability by shifting profits along the value chain.

Transfer pricing risk can also occur in the pricing of the hydrocarbons sold downstream. In the natural gas industry, as previously mentioned, there are different markets. Although natural gas is a homogenous commodity, the peculiar characteristics of the different markets cause a variation in natural gas prices. As seen in figure 2 below, the Asia market (represented by the JKM) tends to fetch the highest prices. This is followed by prices in the European market (represented by the NBP), then by prices in the North American market (represented by the HH).

Figure 2
Natural gas prices in regional markets
(US\$ per mmbtu)



Source: Quandl (2020).

At the inception of the natural gas industry, long term contracts were predominantly used, and the destination market was stipulated in the contracts. In the 2000s, there was an increase in the international trade of natural gas between countries. Furthermore, LNG suppliers and LNG buyers gradually introduced more flexibility in their contracts, allowing the supplier to switch destinations for natural gas.

The experience of Trinidad and Tobago illustrates how a change in the destination market over time. In 1999 when Trinidad and Tobago entered the LNG market, its cargoes were mainly targeted at the US market. This occurred until the year 2007. Post 2007, with the emergence of the shale gas boom in the US, there was a decreased need for the US to import natural gas. Gradually the US became self-sufficient to the point where it started exporting natural gas in 2015. Given the change in the market, Atlantic LNG (ALNG) exported its LNG cargoes to the European, Asia-Pacific, and Latin America and Caribbean (LAC)²⁵ markets, see table 5.

²⁵ Argentina, Brazil, Chile, Mexico, Dominican Republic and Puerto Rico are the countries that import LNG in the LAC Region. Henceforth such countries will be referred as the LAC market.

Table 5
Trinidad and Tobago LNG exports to destination markets (BCM)

Destination	2001	2001 share	2007	2007 share	2018	2018 share
Canada					0.4	
Mexico			0.62		0.3	
US	2.6		12.76		1.8	
North America	2.6	70%	13.38	74%	2.5	15%
Argentina					0.6	
Brazil					0.8	
Chile					2.5	
Dominican Republic			0.36			
Puerto Rico	0.6		0.74			
Other South. & Central America					3.2	
S&C. Amer.	0.6	20%	1.1	6%	7.1	42%
Belgium			0.07		-	
France			0.06		0.1	
Italy					-	
Spain	0.5		2.09		2.2	
Turkey			0.06		0.4	
United Kingdom			0.39		0.8	
Other EU					0.2	
Rest of Europe					-	
Europe	0.5	10%	2.67	15%	3.7	22%
Egypt					0.1	
Kuwait					0.1	
United Arab Emirates					-	
Other Middle East & Africa					0.9	
Middle East & Africa					1.1	
China					0.5	
India			0.21		0.5	
Japan			0.57		0.2	
Malaysia					-	
Pakistan					0.1	
Singapore					0.1	
South Korea			0.22		0.3	
Taiwan					0.3	
Thailand					0.5	
Other Asia Pacific					-	
Asia Pacific			1.00	6%	2.4	14%
Total exports	3.7		18.15		16.8	

Source: BP (2002; 2008; 2019) "Statistical Review of World Energy." Accessed February 28, 2020.

As seen in Table 4, in 2001, 70% of Trinidad and Tobago LNG exports went to the North American market. A similar share of 74% was recorded for 2007. However, by 2018, the share to the North American market dwindled to 15%.

The allocation of natural gas to different markets is not a problem for the LNG exporting country. However, if a government's contract with the LNG exporter is locked into the benchmark price of a specific market, but the LNG cargoes are diverted into higher priced markets, then the government

would not receive a netback based on the higher priced markets. In fact, this could result in a situation where the LNG exporter is exporting to the highest priced markets, but is computing a netback based on the lowest priced market. Since the spreads between the regional markets could be as high as \$10/ mmbtu in bullish periods, it could result in significant loss in revenue for the government.

B. The OECD approach to addressing transfer pricing risk

The arm's length principle is key to avoiding transfer pricing risk (Readhead 2018). The arm's length principle is the requirement for the transfer price for the divisions of the company be the same as if the division involved were indeed independents, and not part of the same corporate structure (Neighbour 2008).

The Organization for Economic Co-operation and Development (OECD) acknowledges that some companies practice transfer pricing with the objective of shifting of profit to reduce their taxation liability. The OECD refers to this practice as "base erosion and profit shifting" (BEPS).²⁶ In response to this challenge, the OECD developed the BEPS initiative, which in turn seeks to close gaps in international taxation framework, that reduces companies' taxation liability. The OECD's BEPS action plan is a 15-point mechanism designed to address the main areas where multinational companies have been most aggressively accomplished in the shifting of profit (See Annex I).

C. Addressing transfer pricing

Many countries that host multinationals in its oil and gas industry have developed regulative responses to transfer pricing. In this regard, countries such as Argentina, Australia, Chile, Germany, Malaysia, and Mexico have developed regulations, and laws based upon the transfer pricing guidelines of the OECD. Other countries have developed transfer pricing rules, which they believe can enforce the arm's length principle. Some countries with extensive transfer pricing regulatory frameworks are reviewed below. These examples are provided to demonstrate that it is possible for countries to develop policy frameworks to address transfer pricing. Furthermore, these examples also reveal the essential elements of policy-setting that can effectively address transfer pricing in the Caribbean.

1. Australia

The Government of Australia passed transfer pricing laws²⁷ to limit the prevalence of transfer pricing in Australia. The law seeks to apply the arm's length principle to prevent multinational companies from shifting their profits from Australia to lower-tax jurisdictions.

In Australia, all tax laws, including transfer pricing laws, are administered by the Australian Taxation Office (ATO). The ATO enforces the transfer pricing laws and mandates that the multinationals demonstrate that the actual financial dealings between its divisions are in accordance with the transactions that might be expected from independent parties.

In 2014, the ATO issued new regulations where the multinational companies were required to prepare and submit income statements to the ATO. Failure to comply with this requirement results in the ATO declaring that the respective companies do not have a Reasonably Arguable Position (RAP) with respect to their transfer prices. This in turn elevates the company to a higher penalty position.

²⁶ The OECD refers to base erosion and profit shifting as corporate strategies used by multinationals to shift profits from higher-tax jurisdictions to lower-tax jurisdictions, resulting in the erosion of the tax-base of the higher-tax jurisdictions.

²⁷ Originally set out in the Subdivisions 815-B to 815-D of the Income Tax Assessment Act 1997, but was amended in 2012 and 2013 (EY 2018; Waterhouse 2018).

In 2017, the Government of Australia passed legislation to implement a Diverted Profits Tax (DPT). This tax empowers the Australian Commissioner of Taxation²⁸ to charge a penalty tax of 40% on the profits deemed to have been diverted out of Australia.

2. Colombia

In Colombia, domestic income taxpayers that engage in transactions with foreign parties, or those in free trade zones or tax havens, are mandated to comply with the country's transfer pricing framework.

The Government of Colombia also applies the arm's length principle. It requires taxpayers obliged by the country's transfer pricing system to report the source of their income, costs, deductions, assets and liabilities. The taxpayers are required to engage in transactions with other parties as if they were independent parties.

Additional requirements are as follows:

- Multinational companies must produce and file a transfer pricing report. The report must include: 1) a master file specifying the relevant information of the multinational group; and 2) a local file, detailing the specific transactions carried out by the subsidiary operating in Colombia.
- Multinational companies are mandated to provide a country-by-country report, detailing the information related to the global multinational group's allocation of income and taxes.
- Multinational groups must notify the authorities in Colombia regarding the identity and tax jurisdiction of the reporting entity of the group.
- Multinationals must verify that intra-division services were in fact supplied, and provide an analysis of the benefits of the service highlight factors such as:
 - (i) the cost of the service;
 - (ii) the amount that a third party would be willing to pay;
 - (iii) the costs registered by the service provider; and
 - (iv) the contracts and agreements to support the invoices.
- Regulating the pricing and depreciation of assets, especially when transferred between multinational divisions.
- Segmented financial information on local operations should be certified by a public accountant or an independent auditor.
- The use of Colombian valuation methods for recording transactions involving stocks.
- For financing transactions, the Colombian authorities should take into consideration financial elements such as the principal, length of maturity, interest, credit rating of the debtor, collaterals, and solvency to determine if it is an arm's length transaction.
- Signing advanced pricing agreements (APAs) between the Colombian authorities and the multinationals for 5- year periods.²⁹

²⁸ The Australian Commissioner of Taxation is the official head of the ATO.

²⁹ An advanced pricing agreement is a price agreement between the taxpayer and the tax authority to determine and set transfer pricing for a set of intra-company transactions.

3. Ghana

The Government of Ghana, together with the African Tax Administrators Forum, has developed transfer pricing regulations. A notable feature of Ghana's anti-transfer pricing regime is the empowering of the Commissioner-General of the Ghana Revenue Authority (GRA) to disallow expenses if it is believed that an attempt is being made by the taxpayer to reduce the tax payable in Ghana.

4. Greenland

Greenland has a comprehensive transfer pricing regulatory framework. It requires multinationals and its affiliated entities to conduct transactions in the arm's length principle. The government requires multinationals to prepare and maintain written transfer pricing documentation for transactions to the local tax authorities. Failure to comply, or an investigation revealing that the transactions were not conducted on an arm's length basis would result in the multinationals paying a fine as a minimum penalty corresponding to twice the expenses that have been saved.

5. India

India's Income Tax Act includes transfer pricing regulations. These regulations require multinational companies to conduct transactions with their divisions based on the arm's length principle. The Income Tax Act has specific criteria for determining the arm's length price, comprising of the assessment of comparable prices, resale prices, cost plus accounting, profit sharing, and a transactional net margin method. The Central Board of Direct Taxes (CBDT) is also empowered to develop additional methods to verify transfer prices. The Government of India has also introduced an advance pricing agreement regime. This system includes the negotiation of prices between the government and the multinationals. The APAs are valid for 5-year periods, and the multinationals are required to file a compliance report with the CBDT each year.

If, on review of the taxpayer's documents, it is revealed that the taxpayer was not compliant with the arm's length principle, the CBDT may impose penalties up to 4% of transaction value for noncompliance with the procedural requirements. The CBDT may charge additional penalties for concealment of profits/income or furnishing inaccurate information. The additional fees may be levied at the rate of 100% to 300% of the tax that the transaction is seeking to evade (EY 2018).

6. Administrative pricing in Norway, Angola, and Indonesia

Some major oil producing countries such as Norway, Angola, and Indonesia, have chosen to adopt administrative pricing as a mechanism to address transfer pricing. Under the administrative pricing system, the government, or a government agency determines the price of the commodity which should be used to compute the taxes (Readhead 2018).³⁰

The governments of Norway, Angola, and Indonesia, all have a similar approach in administrative pricing, which includes:

- the appointment of a task force by the government to set the administrative prices;
- the publishing of the administrative prices on a frequent (daily to monthly) basis;
- the inviting of companies to report on their sales; and
- the creation of system to dispute the administrative prices.³¹

³⁰ Norway pioneered the administrative pricing approach in the 1970s, due to the transfer pricing risk it faced in its oil industry. It's upstream segment of the value chain was taxed at 85%, but the midstream and downstream was taxed at 35%. Subsequently, the vertically integrated multinationals sold the oil to its refinery subsidiaries at below market price, allowing higher profits to be realized downstream (Readhead 2018).

³¹ The government each create a panel of experts to adjudicate potential disputes on administrative prices.

Administrative pricing provides three direct benefits. First, the government can set the arm's length prices. This can remove all ambiguity regarding transfer prices. If the multinational disagrees with the arm's length prices, the onus would be upon the multinational to demonstrate that the government's valuation is incorrect. The second benefit is it provides a simplified framework. This is an attractive feature since local authorities may not have the capacity to assess all of the multinational's intra-company transactions. The third benefit lies in the reduction of ambiguity and likelihood of reduced disputes between the government and the taxpayers.

VI. Estimated revenue loss for Trinidad and Tobago

Transfer pricing could result in significant loss of revenue for natural resource-rich developing countries. The issue is discussed in this paper in an effort to inspire a review of prevailing hydrocarbon-related (crude oil, natural gas, and downstream industries) fiscal policy. In this regard, an important objective of the ensuing analysis is to estimate the potential revenue loss from transfer pricing for Trinidad and Tobago.

The second objective is to empirically model the relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago. This relationship is important because it would facilitate a better understanding of the potential impact of energy revenues on economic activity and growth in energy-exporting Caribbean economies. It is important to note that, of the two study countries, only Trinidad and Tobago is modeled and transfer pricing-related revenue leakage estimated, since transfer pricing currently exists in Trinidad and Tobago's hydrocarbon industry (Poten and Partners 2015). As earlier indicated, Guyana's industry is still in its nascent stage, oil production having only begun in 2020. Currently available data is therefore insufficient to facilitate parallel analysis.

A. Estimated revenue loss in the natural gas industry

Given the absence of the necessary oil sector data for Trinidad and Tobago, the ensuing empirical analysis is restricted to the natural gas sector. As previously mentioned, there are three main regional natural gas markets. As detailed in Section 6.1, there has gradually been a diversification of the destination markets for Trinidad and Tobago's LNG. However, when the natural gas is sold in the higher priced markets, the benefit of the higher prices does not reach the GORTT due to the structure of the natural gas contracts. In fact, the GORTT take from the export of LNG is always approximately \$2/MMBtu (Poten and Partners 2015, 253). This is a form of transfer pricing risk.

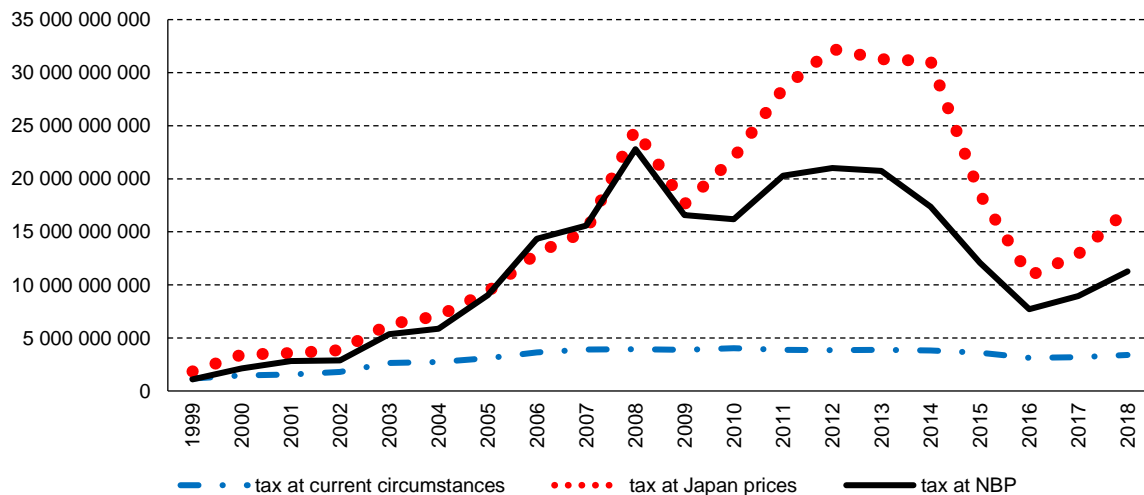
To estimate Trinidad and Tobago's total natural gas revenue, its natural gas export (LNG) can be multiplied by the price of natural gas. Trinidad and Tobago exports approximately 60% of its LNG, while the remaining 40% is used for domestic production. Therefore, Trinidad and Tobago total natural gas

production should be multiplied by 0.60 to derive the LNG exports. The Natural Gas Master Plan notes that the GORTT take from the export of LNG is always approximately \$2/ MMBtu. Therefore, a price of US\$2/mmbtu is used to estimate the current prices received by the GORTT.³²

Three scenarios are also considered for total revenue estimation. These scenarios are considered to reflect the different tax revenues which can be derived if the tax is applied to natural gas exported to different regional markets.

In the first, the current netback price is multiplied by output. In the second, the output is multiplied by Asia-Pacific prices. In the third, the output is multiplied by European prices. To estimate the tax for the government, the total revenue under each scenario is multiplied by 0.35 to reflect the 35% tax rate. To convert the tax revenue from USD to TTD it is multiplied by 6.5. Figure 3 shows the scenarios, while annex 3 displays the data used for the calculation. In 2018, the estimated revenue loss ranged from \$7,855,851,899 (TTD) to \$13,678,883,823 (TTD).

Figure 3
Estimated tax revenues under the 3 scenarios, 1999-2018
 (TT\$)



Source: Central Bank of Trinidad and Tobago data centre.

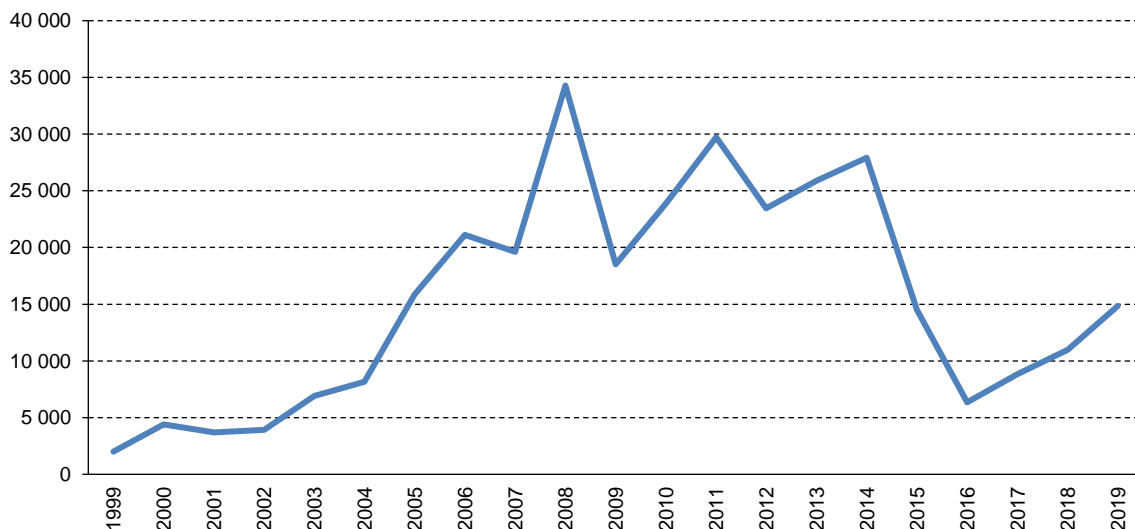
It is noteworthy that the data presented in figure 3 and annex 3 are estimations, and not the actual revenue received by the GORTT. The Central Bank of Trinidad and Tobago (CBTT) reports Trinidad and Tobago total energy revenue. This is the government tax revenue earned from all the sub-industries of the energy sector, including, oil, LNG, and downstream natural gas (petrochemicals). This aggregated tax revenue is displayed in figure 4.

Under the current arrangement, therefore, Trinidad and Tobago is not allowed to fetch higher natural gas prices in other markets when they fluctuate, subsequently resulting in a loss of potential revenue. In fact, over the 2010 to 2014 period while the natural gas price was high, it is estimated that revenue collections by the government could have been approximately five times higher. In 2018, while

³² Trinidad and Tobago’s natural gas production is obtained from BP Statistical Review of World Energy (2019, 2010). This data is quoted in billion cubic meters. To convert to billion cubic feet (bcf), it is multiplied by 35.3107. To convert the gas production from bcf feet to million cubic feet (mmcf), it is multiplied by 1000. Natural gas prices are recorded in million British thermal units (mmbtu). To convert from mcf to mmbtu, the output is multiplied by 1037. The prices are obtained from Quandl database. Japan LNG CIF is used as the benchmark for the Asia-Pacific prices. NBP prices are used as the benchmark for European prices.

prices were low, the government could have received revenue that was approximately six times higher than actual receipts - amounting to an estimated US\$2.6 billion in revenue loss from the natural gas sector alone. Given the results of the empirical analysis reported earlier in this section, this could have a significant positive impact on the country's GDP growth rate, particularly as it seeks to quicken its post-COVID-19 economic recovery. This should also serve a cautionary tale for Guyana, as it navigates the development of the legislative and policy framework that will govern the development of its energy sector.

Figure 4
Trinidad and Tobago central government energy revenue
(TT\$ millions)



Source: Central Bank of Trinidad and Tobago data centre.

B. Relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago

This subsection seeks to investigate the relationship between the Government of the Republic of Trinidad and Tobago's (GORTT) energy revenue and Trinidad and Tobago's GDP. In attempting to determine the appropriate econometric model frame, the data were found to be non-linear, non-stationary and not normally distributed, with three structural breaks.

In view of the foregoing, three main methodologies were utilized to model the relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago. The first was the wavelet transform, used by Reboredo and Rivera-Castro (2013) and Jiang and Yoon (2020) to model the relationship between variables that exhibit non-linearity.

Secondly, the copula, which was employed to measure the dependence between the variables. Traditionally, correlation is commonly used to measure dependence. However, correlation has several limitations; notably:

- It is based on the assumption of normality;
- It is a measure of the linear association between 2 variables; and
- It does not imply causality between variables.

Fortunately, the copula can measure the dependence between two variables and it does not suffer the same limitations as correlation. Furthermore, copulas are attractive because they can measure dependence even when there are extreme movements e.g. jumps and structural breaks.

Thirdly, the Granger causality, a predictive causality test, was applied to determine the existence of a causal relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago.

The wavelet was used to decompose both time series into three levels of details. D_1 refers to 2-4 quarters, D_2 refers to 4-8 quarters, D_3 refers to 8-16 quarters. The results of the Student-t copula reveal that there is strong positive dependence between the GDP decompositions employed. This strong dependence was observed for all the decompositions for both the correlation coefficient, and the Student-t copula. This suggests that Trinidad and Tobago's GDP is likely to move in the same direction as the GORTT's energy revenue. Therefore, growth in the GORTT's energy revenue would be accompanied by GDP growth. Likewise, contraction in the GORTT's energy revenue would be accompanied by contraction in the GDP. Indeed, this confirms the importance of the energy revenue to the economy of Trinidad and Tobago.

The results also reveal that there was Granger causality between the energy revenue and the GDP. However, no causality was found at the 2nd and 3rd levels of detail. Moreover, this suggests that the causal link between the GDP and the GORTT energy revenue dies out over time. In other words, the energy revenue impact upon the real GDP is felt within 2-4 quarters, but dissipates thereafter. These results highlight that the effect of changes in the GORTT energy revenue is felt on the GDP within a short period of time (2-4 quarters). This result is plausible given that energy revenue fluctuates, and it is used often immediately to offset public finance commitments in small developing economies, such as recurrent expenditure, subsidies and transfers and debt service payments (See Annex II).

VII. Policy recommendations

The revenue impact of transfer pricing has been noted by the authorities to exist in Trinidad and Tobago. The recent Natural Gas Master Plan mentions that in times of high LNG prices when there should have been upside sharing as off takers diverted cargoes away from the US to higher value markets there was no increase in value accruing to the government.³³ To present date, there has been no report of transfer pricing in Guyana. However, this is understandable since the country is in the nascent stage\ of its hydrocarbon industry. Neither Guyana nor Trinidad and Tobago possess frameworks for addressing potential transfer pricing in their hydrocarbon industries. Since transfer pricing risk is a common problem occurring in oil and gas industries, it would be logical for transfer pricing legislation to be introduced in Guyana and Trinidad and Tobago.

A. Recommended framework

It is imperative that any framework to address potential transfer pricing in Guyana and Trinidad and Tobago should encourage, even require the conduct of transactions by multinationals using the arm's length principle in order to address, *inter alia*, potential shifting in the destination markets for natural gas. To this end, four essential elements of the recommended framework are outlined below.

³³ Poten and Partners (2015, 252) assert "The US is now no longer an attractive market for LNG but Trinidad and Tobago is stuck with HH as a base price under these marketing arrangements, with the majority of the actual sales revenue now being captured by the marketing entities offshore." They go on to state "Poten's estimate of the combined potential value loss from the four ALNG trains averaged around \$6 billion per year between 2011 and 2014 ... the existing arrangements are not optimally capturing value for Trinidad and Tobago." (Poten and Partners 2015, 254). The Minister of Energy also asserted "In general, Poten and Partners have found that the beneficiary of the substantial value generated by the Trains were not so much the upstream gas suppliers; rather offshore jurisdictions which were either low priced markets or high priced markets but with the revenue not flowing back to Trinidad. In the majority of transactions, the offtake arrangements for upstream companies involve sales to downstream marketing affiliates, which potentially lead to non-arm's length transactions." (Khan 2017, 8).

1. Designate a revenue authority to set a fair price for the hydrocarbons

From the outset, an entity should be designated with responsibility to monitor the prices of crude oil, natural gas, and downstream products in various markets. In Trinidad and Tobago Section 6(A) of the Petroleum Taxes Act establishes the Permanent Petroleum Pricing Committee (PPPC) to determine a fair market price for the taxation petroleum (LTT 2012). In 2018 the Minister of Energy stated that the PPPC was reactivated, following several years of dormancy (Khan 2018).

The PPPC has the jurisdiction to determine the prices for petroleum. However, there is room to expand the jurisdiction of the PPPC to include the review of prices for natural gas, and petrochemical products.³⁴

For Guyana, an authority should also be designated to determine a fair market price for the taxation of crude oil and any potential hydrocarbon products. This recommendation is in line with the practices adopted in countries such as Angola, Australia, Colombia, Ghana, India, Indonesia, and Norway.

2. Implementing advanced pricing agreements

Advanced pricing agreements are an attractive option to address transfer pricing. The government and the multinationals can negotiate the transfer price for various transactions. They can then establish these prices in an advanced pricing agreement, which could hold for five-year periods. The APA should also:

- state a procedure for the monitoring of the transactions;
- establish a reporting framework;
- outline the actions and penalties that may be charged if a party is found to be in breach of the agreement; and
- establish a dispute resolution procedure.

3. Establishing a reporting and monitoring framework

An absence of transparency in transactions is problematic for any country seeking to address transfer pricing risk.³⁵ Therefore, it is crucial that both Guyana and Trinidad and Tobago develop a reporting and monitoring framework. Specifically, the governments could require multinationals to submit the following:

- (i) A master report once every five years specifying the relevant information of the multinational group. This information should include:
 - the parent company;
 - the subsidiaries;
 - related divisions;
 - the jurisdictions in which the companies operate;
 - the tax rates in the jurisdictions; and

³⁴ Section 5 (1) mentions crude oil, natural gas, petroleum products, and petrochemicals. However, it does not clearly state that the PPPC has the jurisdiction to set the price for these products to determine the tax.

³⁵ The Government of the Republic of Trinidad and Tobago Minister of Energy asserted that "An analysis of the marketing arrangements revealed that there is no transparency in the execution of contracts, the marketing companies interpret contract provisions to their own benefit and the lack of audit rights by Government limits its ability to determine contract violations." (Khan 2018, 15).

- the company source of income, costs, and deductions.
- (ii) An annual local report specifying:
 - the local company's income statement (revenue and expenses);
 - balance sheet, which states how assets were depreciated, and transferred;
 - the local company cash flow statement;
 - the price at which the commodity was sold in international markets;
 - the inter-division services;
 - the cost of the services; and
 - the contracts to support the services

The financial statements (income statement, cash flow statement, and balance sheet) that were submitted as part of the annual local should be certified by a reputable independent auditor.

The governments should also endeavor to enact legislation that:

- mandates the companies operating in the entire hydrocarbon value chain locally (upstream, mid-stream, and down-stream) to submit accurate information;
- establishes clearly defined penalties for the deliberate reporting of false information, or the deliberate misrepresentation of information; and
- creates a dispute resolution system to allow the tax-payers to raise and settle disputes with the government regarding prices.

This recommendation is in line with the practices observed in Angola, Colombia, India, Indonesia, and Norway.

4. Addressing the natural gas netback prices

Natural gas can be sold in various markets that fetch different prices. Governments have three avenues to fetch a netback based on the actual market price. The first option is for the government to enter into an advanced-pricing agreement with the natural gas exporting company. Both parties can negotiate the price which should be used to derive the netback to the wellhead for the government. This option would be attractive to both parties since they can negotiate the deemed best for both parties.

A second option would be for a pricing authority to review prices on the international markets, and set a price which it deems is fair. It is noteworthy that this approach can be contentious for the natural gas exporters. However, the potential for dispute can be curbed if the pricing authority is constructed as a tripartite organization comprising the public sector, the private sector and the trade union movement (with advice from academia). Based on consultations with industry stakeholders, and with due consideration given the economics of the various hydrocarbon markets, the tripartite pricing authority could set a price which it deems fair.

A third option lies in the government mandating that the netback price for natural gas be based on the actual export market. While it may be difficult for any government to implement this requirement in isolation, it can be implemented if the requisite legislation is put in place and there is a cohesive monitoring and reporting framework. However, in instances where the government has existing long-term contracts with the natural gas exporting company, this may complicate enforcement (implementation). Furthermore, arbitration on LNG destination prices in international courts can result in unfavorable outcomes for the local stakeholder.³⁶ Therefore, it would be advisable that the parties negotiate and agree upon a gas price and pricing formula in an advanced pricing agreement.

³⁶ In July 1995, Atlantic LNG entered into a 20-year sales contract with Gas Natural Aprovevisionamientos (GNA). ALNG agreed to supply GNA with LNG from its Train I facility. The contract allowed GNA to transport the LNG to its receiving facilities in Spain or to a facility in New England. As the European market was expected to be the destination market for the gas, the LNG pricing contract used the European market as the benchmark to compute the netback. The contract also included a price reopener clause to allow parties to renegotiate prices if the economics changes. The economic conditions did indeed change, as the Spanish market became liberated, and the LNG offtake ended up in the North American market. The parties ALNG and GNA ended up in a dispute regarding the prices. After years of arbitration in the court (United States District Court, S.D. New York), the arbitration panel handed down an award on January 17, 2008 that sought to maintain a reasonable profitability for GNA under the changed market conditions (In GNA v. Atlantic LNG Co. of Trinidad & Tobago 2008).

VIII. Conclusion

The extraction and the sale of natural resources has the potential to generate natural resource booms and significantly increase government revenues. Governments of such resource rich countries rely on natural resource rents to fund their development objectives.

Developing countries which lack the capacity to commercially produce and monetize their natural gas resources on their own tend to rely upon multinational energy companies. Indeed, MECs operate in interconnected global value chains in the process of bringing the hydrocarbons from the ground to the consumer to the final market. Since multinationals tend to be vertically integrated, they tend to have different subsidiaries and divisions operating in different segments of the global value chain. These multinationals often conduct business with their different divisions. While business between the divisions is not a problem, the manipulation of costs can cause the shifting of profits along the value chain, resulting in the changing of taxpayers' tax liability.

Certainly, there is a dilemma. The attraction of multinationals, perhaps through incentives, facilitates the earning of natural resource rents and encourages economic activity in countries. However, doing business with large players with fragmented yet interconnected global value chains, creates several opportunities for the erosion of taxable income.

Moreover, the COVID-19 pandemic had had pernicious multi-sectoral economic and financial impacts on the economies of the subregion, considerably reducing fiscal revenues by as much as 75% in some Caribbean economies. It has also led to significant growth in fiscal spending. This has dampened liquidity in many Caribbean countries, which were already challenged by high levels of public debt and fiscal deficits, both of which have worsened in 2020. Hence, for subregional energy exporters, optimizing natural resource rents has not surprisingly re-emerged as a leading short-term policy objective for the post-COVID-19 era.

Fortunately, transfer pricing risk, base erosion, and profit shifting are not inescapable outcomes. Governments can devise a proper policy and legislative framework to avoid the leakage of potential resource rents. Indeed, the magnitude of the estimated revenue losses incurred by Trinidad and Tobago

in its natural gas sector due to transfer pricing risk suggests that this a sufficiently significant issue for the governments of the energy exporting Caribbean economies to pay urgent attention to and seek to address through the recommendations advanced in this study.

Moreover, transfer pricing risk can be mitigated if the public authorities mandate the multinational companies to charge prices between their respective subsidiaries using the arm's length principle. If this is done, it would encourage transactions at market rates, and prevent the shifting of profits along the global value chain, thus allowing the developing country to capture its fair share of its natural resource rents.

This notwithstanding, ideally the fiscal terms that govern hydrocarbon projects should be sufficiently flexible to ensure that, as conditions change, investors and the government could work to resolve them in a mutually supportive way. Arguably, because hydrocarbon projects tend to be long-term investments (20 years or more), multinational oil companies have a strong incentive to maintain a positive relationship with the developing country, including its tax authority. In this regard, this paper also identifies possible areas for further study, such as expanding the focus of the analysis to include Latin American economies and employing a game theory framework³⁷ to find the optimum solution to the transfer pricing conundrum facing the Latin American and Caribbean energy exporters alike.

³⁷ Game theory is a theoretical framework which can be used to explain decision making between competing players. Game theory, which has been applied in energy economics, can be useful for governments in negotiations with multinational energy companies (MECs).

Bibliography

- Aguilera, Roberto F., Julian Inchauspe, and Ronald D. Ripple (2014), "The Asia Pacific Natural Gas Market: Large Enough for All?" *Energy Policy* 65: 1-6.
- Arvanitis, Stavros, Irakleia Tzigkounaki, Theodoros V. Stamatopoulos, and Eleftherios Ioannis Thalassinos (2012), "Dynamic Approach of Capital Structure of European Shipping Companies." *International Journal of Economic Sciences and Applied Research* 5 (3): 33-63.
- Asche, Frank, Atle Oglend, and Petter Osmundsen (2012), "Gas versus Oil Prices the Impact of Shale Gas." *Energy Policy* 47: 117-124.
- Balza, Lenin, H., Emily Brearley, Dillon Clarke, and Victor Gauto (2020), "Traversing a Slippery Slope: Guyana's Oil Opportunity." Technical Note No IDB-TN-1994, Inter-American Development Bank.
- Barroso, Luiz Augusto, Hugh Rudnick, Sebastian Mocarquer, Rafael Kelman, and Bernardo Bezerra (2008), "LNG in South America: The Markets, the Prices and the Security of Supply." In *2008 IEEE Power and Energy Society General Meeting-Conversion and Delivery of Electrical Energy in the 21st Century, 20-24 July 2008*, edited IEEE, 1-6. Pittsburgh, United States.
- Baru, Penerbit Akademia (2019), "Logistics Management for Organizational Success of Downstream Industry in Oil & Gas." Accessed February 24, 2020. https://www.researchgate.net/publication/330701153_Logistics_Management_for_Organizational_Success_of_Downstream_Industry_in_Oil_Gas/figures?lo=1.
- Boopsingh, Trevor M, and Gregory McGuire, eds. (2014), *From Oil to Gas and Beyond: A Review of the Trinidad and Tobago Model and Analysis of Future Challenges*. New York: University Press of America.
- British Petroleum (BP) (2002), "Statistical Review of World Energy." Accessed February 28, 2020. <https://www.griequity.com/resources/industryandissues/Energy/bp2002statisticalreview.pdf>.
- _____(2008), "Statistical Review of World Energy." Accessed February 28, 2020. http://large.stanford.edu/publications/power/references/docs/statistical_review_of_world_energy_full_review_2008.pdf.
- _____(2019), "Statistical Review of World Energy." Accessed February 28, 2020. <https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html>.

- _____(2020), "Statistical Review of World Energy." Accessed November 2, 2020. <https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2020-full-report.pdf>.
- Buenos Aires Herald (BAH) (2013), "Argentina losing LNG supplies to Brazil, Japan, South Korea." Accessed February 24, 2020.
- Campbell, Jacob (2009), "The Political Economy of Natural Gas in Trinidad and Tobago." Caribbean Development Report. Accessed March 23, 2016. http://repositorio.cepal.org/bitstream/handle/11362/3707/LCW249_en.pdf?sequence=1#page=273.
- Central Bank of Trinidad and Tobago (CBTT) (2020), "Public Finance - Annual." Accessed November 4, 2020. <https://www.central-bank.org.tt/statistics/data-centre/public-finance-annual>
- Charles, Don (2016), "COP 21 and the Evolution of Climate Change Governance." *International Journal of Green Economics*, 10 (3-4): 287-301.
- _____(2019), "A Nationally Determined Contributions Roadmap Towards a Low Carbon Economy for Trinidad and Tobago." In *Towards Climate Action in the Caribbean Community*. Cambridge, United Kingdom: Cambridge Scholars Publishing.
- Chen, Shiu-Sheng, and Kai-Wei Hsu (2012), "Reverse Globalization: Does High Oil Price Volatility Discourage International Trade?" *Energy Economics* 34 (5): 1634-1643.
- Cherubini, Umberto, Elisa Luciano, and Walter Vecchiato (2004), *Copula Methods in Finance*. Hoboken, New Jersey, United States: John Wiley & Sons.
- Cunningham, Nick (2014), "Market Disruptor: Nuclear Restarts Spells Trouble for LNG." *Oil Price*, January 15. Accessed February 11, 2015. <https://oilprice.com/Energy/Natural-Gas/Market-Disruptor-Nuclear-Restarts-Spells-Trouble-for-LNG.html>.
- Davoust, Romain (2008), "Gas Price Formation, Structure, and Dynamics." Accessed June 21, 2013. <https://www.ifri.org/sites/default/files/atoms/files/notedavoust.pdf>
- Deloitte Center for Energy Solutions (DCES) (2013), "Exporting the American Renaissance Global impacts of LNG exports from the United States." Accessed June 14, 2014. http://www.deloitte.com/assets/Dcom-UnitedStates/Local%20Assets/Documents/Energy_us_er/us_er_GlobalImpactUSLNGExports_AmericanRenaissance_Jan2013.pdf.
- Energy Year (2019), "Guyana: The Launch of a New Era." Accessed November 2, 2020. <https://theenergyyear.com/market/guyana/>.
- Erdos, Peter, and Mihaly Ormos (2012), "Natural Gas Prices on Three Continents." *Energies* 5 (10): 4040-4056.
- Ernst and Young (EY) (2018), "Global Oil and Gas Tax Guide." Accessed February 25, 2020. [https://www.ey.com/Publication/vwLUAssets/ey-global-oil-and-gas-tax-guide/\\$FILE/ey-global-oil-and-gas-tax-guide.pdf](https://www.ey.com/Publication/vwLUAssets/ey-global-oil-and-gas-tax-guide/$FILE/ey-global-oil-and-gas-tax-guide.pdf).
- Fahim, Mohamed A., Taher A. Al-Sahhaf, and Amal Elkilani (2009), *Fundamentals of Petroleum Refining*. Amsterdam, Netherlands: Elsevier.
- Geman, Hélyette (2009), *Commodities and Commodity Derivatives: Modeling and Pricing for Agriculturals, Metals and Energy*. New York City, United States: John Wiley and Sons.
- GNA v. Atlantic LNG Co. of Trinidad & Tobago (2008), 08 Civ. 1109 (DLC).
- Government of the Republic of Trinidad and Tobago, Ministry of Energy and Energy Industries (GORTT MEEI) (2016), "Historical Facts on the Petroleum Industry of Trinidad and Tobago." Accessed January 3, 2016. <https://www.energy.gov.tt/historical-facts-petroleum/>.
- _____(2020), "Downstream Annual Reports." Accessed November 2, 2020. <https://www.energy.gov.tt/publications/downstream-annual-reports/>.
- Government of the Republic of Trinidad and Tobago, Office of the Prime Minister (GORTT OPM) (2017), "Prime Minister Rowley Provides Update on Gas Situation After Visit to Houston." Accessed

- November 2, 2020. <https://www.opm.gov.tt/pms-statement-on-natural-gas-situation-in-tt-and-visit-to-houston/>.
- Granger, Clive W.J. (1969), "Investigating Causal Relations by Econometric Models and Cross-Spectral Methods." *Econometrica: Journal of the Econometric Society* 37 (3), 424.
- Hamilton, James D. (1983), "Oil and the Macroeconomy since World War II." *The Journal of Political Economy* 91 (2): 228-248.
- Hosein, Roger (2010), "Booming Mineral Resources and the Imperative of Economic Diversification." *The West Indian Journal of Engineering* 32 (1): 2-20.
- International Energy Agency (IEA) (2012), Natural Gas Information 2012. Accessed June 3, 2014. <http://www.iea.org/media/training/presentations/statisticsmarch/NaturalGasInformation.pdf>
- Jiang, Zhuhua, and Seong-Min Yoon (2020), "Dynamic Co-Movement Between Oil and Stock Markets in Oil-Importing and Oil-Exporting Countries: Two Types of Wavelet Analysis." *Energy Economics* 90: 1-34.
- Jobity, Richard and Pantor, Robert (1995), "The Natural Gas Industry in Trinidad and Tobago, Central Bank of Trinidad and Tobago." Accessed January 5, 2014. http://ngc.co.tt/wp-content/uploads/pdf/NGC_Webinar_The%20Structure_History_and_Role_of_the_Natural_Gas_Industry_2013-08-22.pdf.
- Khan, Franklin (2017), "Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries, Speech, Senator The Honourable Franklin Khan, Minister of Energy and Energy Industries, Energy Chamber Annual Conference, Maximizing Value Through Collaboration." Accessed February 27, 2020. https://ngc.co.tt/wp-content/uploads/2018/02/2018-01-22_speech_maximising-value-collaboration_energy-conference-2018_franklin-khan.pdf.
- _____(2018), "Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries, Speech Senator the Honourable Franklin Khan Minister of Energy and Energy Industries Energy Spot Light Our Oil, Our Gas, Our Future Hyatt Regency, Port Of Spain." Accessed February 28, 2020. https://www.finance.gov.tt/wp-content/uploads/2018/03/HM-Franklin-Khan-Energy-Spotlight-Speech-Delivered-14_3_18.pdf.
- Kilian, Lutz (2016), "The Impact of the Shale Oil Revolution on US Oil and Gasoline Prices." *Review of Environmental Economics and Policy* 10 (2): 185-205.
- Krauss, Clifford (2017), "With a Major Oil Discovery, Guyana Is Poised to Become a Top Producer." *The New York Times*, January 13. Accessed February 22, 2018. <https://www.nytimes.com/2017/01/13/business/energy-environment/major-oil-find-guyana-exxon-mobile-hess.html>.
- Laws of Trinidad and Tobago (LTT) (2012), "Petroleum Taxes Act, of 1974. Amended by 13 of 2010." Accessed February 28, 2020. http://www.energy.gov.tt/wp-content/uploads/2013/11/Petroleum_Taxes_Act.pdf.
- Maina, Anne Wanyagathi (2019), "The Kenyan Tax Regime for the Oil and Gas Sector: An International Tax Perspective to Policy and Practical Challenges." *Revista Derecho Fiscal* 14: 1-17.
- Massa, Ricardo, and Juan Rosellon (2020), "Linear and Nonlinear Granger Causality Between Electricity Production and Economic Performance in Mexico." *Energy Policy* 142: 1-8.
- Maxwell, Don, and Zhen Zhu (2011), "Natural Gas Prices, LNG Transport Costs, and the Dynamics of LNG Imports." *Energy Economics* 33 (2): 217-226.
- Meyer, Richard F., and Emil Attanasi (2004), "Natural Bitumen and Extra-Heavy Oil." In *2004 Survey of Energy Resources*, edited by Judy Trinnaman and Alan Clarke, 93-117. Amsterdam, Netherlands: Elsevier Science.
- Melling, Anthony J. (2010), "Natural Gas Pricing and its Future: Europe as the Battleground." Accessed June 14, 2014. http://carnegieendowment.org/-files/gas_pricing_europe.pdf.
- Morris, Dave (2019), "Europe Markets Climb as Oil Prices Rise On Tanker Incident." *Market Watch*, June 13. Accessed June 13, 2019. <https://www.marketwatch.com/story/europe-markets-climb-as-oil->

- prices-rise-on-tanker-incident-2019-06-13?fbclid=IwAR0RwsmzIBZe4eDjf0ZO57CHZ6y14PLHdAF1StHGaXeX5911KMAIChxgYg.
- Mulchansingh, Vernon C. (1971), "The Oil Industry in the Economy of Trinidad." *Caribbean Studies* 11 (1): 73-100.
- Neighbour, John (2008), "Transfer Pricing: Keeping it at Arm's Length." *OECD Observer*, July 3. Accessed February 26, 2020. https://oecdobserver.org/news/archivestory.php/aid/670/Transfer_pricing:_Keeping_it_at_arms_length.html.
- Offshore Energy Today (OET) (2016), "ExxonMobil boosts estimates for Liza oil discovery (Guyana)." Accessed February 24, 2019. <https://www.offshoreenergytoday.com/exxonmobil-boosts-estimates-for-liza-oil-discovery-guyana/>.
- Offshore Technology (OT) (2018), "The World's Biggest Oil and Gas Companies." Accessed February 24, 2020. <https://www.offshore-technology.com/features/largest-oil-and-gas-companies-in-2018/>.
- Oil and Gas Journal (OGJ) (2018), "ExxonMobil: Guyana Drilling, Development Work Continues." Accessed February 24, 2019. <https://www.ogj.com/articles/2018/12/exxonmobil-guyana-drilling-development-work-continues.html>.
- Organization for Economic Co-operation and Development (OECD) (2013), *Action Plan on Base Erosion and Profit Shifting*. Paris, France: OECD Publishing.
- Pantin, Dennis (1988), "Whither Pt, Lisas? Lessons for the future." In *Trinidad and Tobago: The Independence Experience, 1962- 1987*, edited by S. Ryan, 27-45. Trinidad: ISER.
- Patton, Andrew (2001), "Modelling Time-Varying Exchange Rate Dependence Using the Conditional Copula." Discussion Paper 2001-09, Department of Economics, University of California, San Diego, United States.
- Porter, Micheal. E. (1985), *Competitive Advantage: Creating and Sustaining Superior Performance*. New York, United States: The Free Press.
- Poten and Partners (2015), "Trinidad & Tobago Gas Master Plan Final Report." Accessed February 27, 2016.
- Punnett, C. and John-Toney, B. (2001), "The Philosophy and Policy Underpinnings of the Local Natural Gas Industry." *Gasco News – The Corporate Journal of the National Gas Company of Trinidad and Tobago Limited* 14 (3): 1-4.
- Quandl (2020), "Core Financial Data." Accessed February 28, 2020. https://www.quandl.com/data/BP/GAS_PRICES-Natural-Gas-Prices-vs-Crude.
- Razin, Assaf, and Efraim Sadka (2012), "Tax Competition and Migration: The Race-To-The-Bottom Hypothesis Revisited." *CESifo Economic Studies* 58 (1): 164-180.
- Readhead, Alexandra (2018), "What Mining Can Learn from Oil: A Study of Special Transfer Pricing Practices in the Oil Sector, and their Potential Application to Hard Rock Minerals." CGD Policy Paper. Washington, DC: Center for Global Development. <https://www.cgdev.org/sites/default/files/what-mining-can-learn-oil-study-special-transfer-pricing-practices-oil-sector.pdf>.
- Reboredo, Juan C., and Miguel A. Rivera-Castro (2013), "A Wavelet Decomposition Approach to Crude Oil Price and Exchange Rate Dependence." *Economic Modelling* 32: 42-57.
- Ren, Tao, Bert Daniëls, Martin K. Patel, and Kornelis Blok (2009), "Petrochemicals from Oil, Natural Gas, Coal and Biomass: Production costs in 2030–2050." *Resources, Conservation and Recycling* 53 (12): 653-663.
- Sklar, A. (1959), *Fonctions de Repartition A N Dimensions Et Leurs Marges*. Publ. Inst. Statist. Univ. Paris 8: 229-231.
- Sonstebo, Eirik Aakvik (2012), "The Impact of Natural Gas Exports from the US to Europe. Master of Science in Economics and Business Administration Thesis at the Norwegian School of Economics and Business Administration (NHH).

- Sunley, Emil M., Thomas Baunsgaard, and Dominique Simard (2002), "Revenue from the Oil and Gas Sector: Issues and Country Experience." Accessed February 25, 2020. <http://siteresources.worldbank.org/INTTPA/Resources/SunleyPaper.pdf>.
- Swenson, Deborah L. (2000), "Tax Reforms and Evidence of Transfer Pricing." Accessed February 26, 2020. https://www.researchgate.net/profile/Deborah_Swenson/publication/228132488_Tax_Reforms_and_Evidence_of_Transfer_Pricing/links/55689b3f08aeccd77739ccb8.pdf
- The Energy Year (2019), "Trinidad and Tobago: Poised for New Growth." Accessed February 22, 2020. <https://theoilandgasyear.com/market/trinidad-and-tobago-2/>
- United States Energy Information Administration (US EIA) (2019), "Petroleum and Other Liquids." Accessed December 14, 2019. <https://www.eia.gov/international/data/world/petroleum-and-other-liquids/annual-petroleum-and-other-liquids-production?>
- Trivedi, Pravin, and David Zimmer (2005), "Copula Modelling: An Introduction for Practitioners." *Foundations and Trends in Econometrics* 1 (1): 1-111.
- van Marcke, Gauthier, and A. Dumitrasc (2013), "Opportunities and Challenges of using LNG as Fuel in Small to Medium-Sized Power Generation." Accessed June 13, 2014. http://www.gastechnology.org/Training/Documents/LNG17-proceedings/10-3-Gauthier_van_Marcke.pdf.
- Waterhouse, Tania (2018), "Transfer Pricing in Australia: Overview." Accessed February 27, 2020. [https://uk.practicallaw.thomsonreuters.com/w-007-5260?transitionType=Default&contextData=\(sc.Default\)&firstPage=true&bhcp=1](https://uk.practicallaw.thomsonreuters.com/w-007-5260?transitionType=Default&contextData=(sc.Default)&firstPage=true&bhcp=1).
- Wlazlowski, Szymon, Björn Hagströmer, and Monica Giulietti (2011), "Causality in Crude Oil Prices." *Applied Economics* 43 (24): 3337-3347.
- World Bank (2009), "The Petroleum Sector Value Chain." Accessed February 24, 2020. http://siteresources.worldbank.org/INTOGMC/Resources/noc_chapter_1.pdf.
- _____(2015), "Comparison of Mini-Micro LNG and CNG for Commercialization of Small Volumes of Associated Gas." Accessed February 24, 2020. <http://documents.worldbank.org/curated/en/795991484736761603/Comparison-of-Mini-Micro-LNG-and-CNG-for-commercialization-of-small-volumes-of-associated-gas>.
- _____(2017), "Guyana." Accessed December 10, 2017. <https://data.worldbank.org/country/Guyana>.

Annexes

Annex 1

Summary of the OECD's BEPS action plan

Table A1
Summary of the OECD's BEPS action plan

Action	Description
ACTION 1	Address the tax challenges of the digital economy
ACTION 2	Neutralize the effects of hybrid mismatch arrangements
ACTION 3	Strengthen CFC rules
ACTION 4	Limit base erosion via interest deductions and other financial payments
ACTION 5	Counter harmful tax practices more effectively, taking into account transparency and substance
ACTION 6	Prevent treaty abuse
ACTION 7	Prevent the artificial avoidance of PE status
ACTION 8	Transfer Pricing of Intangibles
ACTION 9	Transfer pricing of risk and capital
ACTION 10	Transfer pricing of other high-risk transactions
ACTION 11	Establish methodologies to collect and analyse data on BEPS and the actions to address it
ACTION 12	Require taxpayers to disclose their aggressive tax planning arrangements
ACTION 13	Re-examine transfer pricing documentation
ACTION 14	Make dispute resolution mechanisms more effective
ACTION 15	Develop a multilateral instrument

Source: Organization for Economic Co-operation and Development) (2013), Action Plan on Base Erosion and Profit Shifting. Paris, France: OECD Publishing.

Annex 2

Econometric analysis: relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago

1. Data

The relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago is analyzed. First data is collected for the GDP and the GORTT's energy revenue. GDP at market prices was obtained from the CBTT database. Data was sought over the 1999 to 2019 period. This period was selected since Trinidad and Tobago commenced its export of LNG from 1999. To account for the differences in prices, the data was rebased using the retail price index with the 2015 base year.

The data on the GORTT's energy revenue was obtained from the CBTT database over the 1999 to 2019 period. Notably, the data collected was at the annual frequency, however, taxes are paid quarterly. Additionally, the time period 1999 to 2019 produced only 21 observations per variable, which is relatively small sample to make inferences. This is sample size limitation is addressed by transforming the data from the annual frequency to the quarterly frequency.

The frequency conversion can be performed in MatLab. The Linear-match last method was used to extrapolate the higher frequency. This can be done by inserting last the low observation value into the last period of the high-frequency data, then performing a linear interpolation on the missing values.

2. Methodology – outline

Before any analysis is applied, a series of pretest is applied. First the data is tested for stationarity. Second the data is tested for structural breaks. The structural breaks test is necessary to determine if the data exhibits a linear or non-linear pattern. If the data is non-linear, then a non-linear methodology would be required.

This study uses 3 main methodologies used to model the relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago. The first is the wavelet transform. This approach is adopted as it was used by Reboredo and Rivera-Castro (2013) and Jiang and Yoon (2020) to model the relationship between variables that exhibit non-linearity.

The second methodology used is the copula, the measure the dependence between the variables. The copula is used since it is a better measure of dependence than correlation.

Third, a predictive causality test is applied to determine the existence of a causal relationship between the GORTT's energy revenue and the GDP of Trinidad and Tobago.

3. Methodology – wavelet transform

A wavelet is a transformation that can be used to decompose a time series. It is a rapidly decaying wave-like oscillation that has zero mean. The wavelet transform utilizes a function referred to as a mother wavelet, that is scaled and shifted to represent the features in the time series.

Scaling refers to the process of stretching or shrinking the wavelet. This is denoted by

$$\Psi\left(\frac{t}{s}\right) s > 0 \quad (01)$$

where t denotes time, and s refers to the scaling factor, which is a positive value. The scaling factor is inversely proportional to frequency.

The shifting of a wavelet refers to the moving of the wavelet along the length of the signal to a position to where it is centered. Mathematically, this is expressed as $\phi(t - k)$

The wavelet transform decomposes a signal into an approximation and details. The approximation is a sub-sample that is a true representation of the original signal. Furthermore, we can recover the original signal from the approximation. Most of the information from the original signal is in the approximation, while the remaining information is in the details coefficients.

$$S_{j,k}(x) = \int_{-\infty}^{\infty} \phi_{j,k}y(x)dx \quad (02)$$

$$D_{j,k}(x) = \int_{-\infty}^{\infty} \psi_{j,k}y(x)dx \quad (03)$$

Equation (02) is the approximation, and Equation (03) is the detail. The signal is given by x .

The D_1, D_2, \dots, D_j are associated with the oscillations of length $2^{-4}, 4^{-8}, \dots, 2^j - 2^{j+1}$ (Reboreda and Rivera-Castro 2013). Since as the frequency used in this study was quarterly, D_1 refers to 2-4 quarters, D_2 refers to 4-8 quarters, D_3 refers to 8-16 quarters. Therefore, D_1 the highest frequency component represents the shortest-term variations. The D_3 is the lowest frequency and represents the long-term variation.

4. Methodology – copula

A copula is a multivariate cumulative distribution function which can be used to describe the dependence between random variables. Copulas are widely used in financial economics to measure the co-movement between variables, especially those that exhibit non-linear characteristics (Cherubini et al. 2004).

Sklar (1959) introduced the theorem underlying copulas. An n -dimensional distribution can be decomposed into its n marginal distributions, and a copula which completely describes the dependence between the variables (Patton 2001). Succinctly stated, copulas are functions that connect marginal distributions of 2 variables into a joint distribution (Trivedi and Zimmer 2005).

Given 2 random variables X_1 and X_2 . The marginal cumulative distribution function (CDF)³⁸ for each of the variables may be denoted by

$$F(X_i) = Pr[X_i \leq x_i], i = 1, 2 \quad (04)$$

where F refers to the function; X_i is denotes the random variable which can be X_1 or X_2 ; and Pr is the probability.

To connect the marginal CDFs, they could be first be transformed to a uniform distribution in the interval $(0,1)$, then a copula may be applied. The corresponding joint CDF may be expressed by

$$H_{X_1X_2}(X_1, X_2) = Pr(X_1 \leq x_1, X_2 \leq x_2) \quad (05)$$

After the copula is applied, the joint CDF is a combination of the 2 marginal CDFs.

$$H_{X_1X_2}(X_1, X_2) = C(F(X_1), F(X_2)) \quad (06)$$

A copula is relevant for the following reasons.

- (i) It can be used to form joint distributions, especially when modelling economic data with marginal distributions that are non-stationary and difficult to combine
- (ii) It can be used when researchers are interested if specific economic variables exhibit dependence, particularly in the tails of the joint distributions
- (iii) It can be used when variables do not have an elliptical joint distribution.³⁹

³⁸ The marginal CDF means the CDF for individual variables.

³⁹ When variables have an elliptical joint distribution, correlation is sufficient to describe their dependence (Patton 2001).

(iv) Copulas can capture dependence structures regardless of the form of the marginal distribution.

Notably, there are several families of copulas. They include:

(i) Product - with the CDF given by

$$C(u_1, u_2) = u_1 u_2 \quad (07)$$

This copula is used as the benchmark.

(ii) Farlie–Gumbel–Morgenstern (FGM) - with the CDF given by

$$C(u_1, u_2; \theta) = u_1 u_2 (1 + \theta(1 - u_1)(1 - u_2)) \quad (08)$$

If the dependence parameter θ falls to 0, this suggests independence between the variables.

(iii) Gaussian (Normal) copula – with the formula given by

$$C(u_1, u_2; \theta) = \Phi_G(\Phi^{-1}(u_1), \Phi^{-1}(u_2); \theta) \quad (09)$$

where Φ is the CDF of the normal distribution, and $\Phi_G(u_1, u_2)$ is bivariate normal distribution with dependence θ parameter restricted to the interval $(-1, 1)$. This copula is symmetric, and allows for equal dependence in the positive and negative tail. It is appropriate for modelling normal distributions.

(iv) Student's t copula – with the formula given by

$$C^t(u_1, u_2; \theta_1, \theta_2) = \int_{-\infty}^{t_{\theta_1}^{-1}(u_1)} \int_{-\infty}^{t_{\theta_2}^{-1}(u_2)} \frac{1}{2\pi(1-\theta^2)^{1/2}} \quad (10)$$

The Student t copula is also symmetric, with equal dependence in the tails.

(v) Clayton copula – is modeled by

$$C(u_1, u_2; \theta) = (u_1^{-\theta} + u_2^{-\theta} - 1)^{-1/\theta} \quad (11)$$

This copula is asymmetric and can only account for negative dependence. It is appropriate in distributions with strong left tail dependence and relatively weak right tail dependence.

(vi) Frank copula – is expressed by

$$C(u_1, u_2; \theta) = -\theta^{-1} \log \left\{ 1 + \frac{(e^{-\theta u_1} - 1)(e^{-\theta u_2} - 1)}{e^{-\theta} - 1} \right\} (u_1^{-\theta} + u_2^{-\theta} - 1)^{-1/\theta} \quad (12)$$

The Frank copula is appropriate where the strongest dependence is centered in the middle of the distribution. Alternatively expressed, it is relevant where the variables exhibit weak tail dependence.

(vii) Gumbel copula – which is modelled by

$$C(u_1, u_2; \theta) = \exp(-(u_1^{\sim\theta} + u_2^{\sim\theta})^{1/\theta}) \quad (13)$$

The Gumbel copula is asymmetric. It exhibits strong right tail dependence and relatively weak left tail dependence (Trivedi and Zimmer 2005).

For the purposes of this study, the Student t copula is used, since it has dependence in both tails of the distribution. Furthermore, there was no a priori information about dependence being a 1 tail to suggest use of the Archimedean family (Clayton, Frank, and Gumbel) of copulas.

5. Methodology – predictive causality

The Granger causality test is a statistical hypothesis test to investigate if time series of one variable could be used to predict the future value of another variable. Granger (1969) noted that the coefficients in regressions reflect correlations between variables. He argued that causality in economics could be tested by measuring the extent in which the past values of one variable could be used to predict the future values of another variable.

Granger hypothesized that a cause should occur before an effect, and a cause should have information about future values of an effect. Based on these assumptions, Granger developed a test to investigate the causal relationship between variables.

This test is performed in several steps. First, a univariate autoregression is performed, where past values of the variable Y are used to forecast future values of itself. Then the regression is amended by including past values of X. In the regression, once all the lagged values of X are individually statistically significant from zero based on the t-statistic, and collectively based on the F-statistic, then it is concluded that X is a Granger-cause of Y.

Granger argues that a weakly stationary time series X can be said to Granger-cause Y if it can be shown, usually through a series of t-tests and F-tests that lagged values of X can provide statistically significant information to predict future values of Y. Therefore, Granger-causality is really predictive causality.

However, the Granger-causality test was based on a linear regression. Therefore, it does not account for non-linear causal relationships. Furthermore, the time series must be stationary in the weak sense, or integrated of the same order in order to satisfy the Granger-causality requirements (Massa and Rosellon 2020).

These conditions highlight the importance for a non-linear framework to model the relation between variables when they exhibit non-stationarity and non-linearity.

6. Results – pretesting

First, some basic descriptive statistics is applied. This is useful to determine if the data is normally distributed. Note, the pretests were applied to both the quarterly and the annual data and produced the same results.

Table A2
Descriptive statistics

	GDP	REV
Mean	176214.5	15728.35
Median	177330.8	14854.70
Maximum	273459.0	34282.10
Minimum	114676.7	1999.700
Std. Dev.	36950.92	9071.079
Skewness	0.542616	0.095418
Kurtosis	2.653186	1.631676
Jarque-Bera	4.380773	6.441962
Probability	0.111873	0.039916
Sum	14273375	1273996.
Sum Sq. Dev.	1.09E+11	6.58E+09
Observations	81	81

Source: Author's compilation.

The null hypothesis of the Jarque-Bera test is the joint hypothesis of the skewness being zero and the excess kurtosis being zero. In other words, the null hypothesis is the series is normally distributed. The probability of the Jarque-Bera test statistic was greater than the 10% level of significance for the GDP. This suggested that the GDP is normally distributed. However, as the probability of the Jarque-Bera test statistic was less than the 10% level of significance for the GORTT energy revenue, it suggested that the revenue is not normally distributed.

The stationarity test results are displayed in table A3.

Table A3
Stationary tests

	GDP	Energy revenue
ADF (level)	0.2351	0.1726
ADF (1 st diff)	0.3410	0.4117
ADF (2 nd diff)	0.0000	0.0000
PP (level)	0.3936	0.3969
PP (1 st diff)	0.0049	0.0020
Perron (level)	0.7337	0.7685
Perron (1 st diff)	0.01	0.7585
Perron (2 nd diff)		0.01

Source: Author's compilation.

The null hypothesis of the ADF and the Philipps-Perron (PP) tests is the series exhibit 1 unit root. In Table 8, at level, and at 1st difference, the probability of the ADF test statistic was greater than the 10% significance level. This suggested the non-rejection of the null hypothesis that the series had at least 1 unit root at level and 1st difference. Only at 2nd difference, the probability of the ADF test statistic fell below the 10%, 5%, and 1% significance level, suggesting the rejection of the null hypothesis. This results indicated that the GDP had 2 unit roots.

In comparison, the probability of the test statistic for the PP, and the Perron unit root with breakpoint test fell in the rejection area only at 1st difference. These tests suggested that the GDP had 1 unit root.

With reference to the GORTT energy revenue, the ADF and the Perron test suggest that it had 2 unit roots. The ADF test suggests that the GDP has 2 unit roots. But the PP and the Perron test suggest that the GDP has 1 unit root.

The structural break test results are displayed in tables A4 and A5.

Table A4
Structural break test for GDP

Sequential F-statistic determined breaks:			
			3
Break Test	F-statistic	Scaled F-statistic	Critical Value ^b
0 vs. 1 ^a	40.71482	40.71482	8.58
1 vs. 2 ^a	91.15180	91.15180	10.13
2 vs. 3 ^a	21.68952	21.68952	11.14
3 vs. 4	0.000000	0.000000	11.83

Break dates:		
	Sequential	Repartition
1	2003Q4	2005Q1
2	2015Q2	2009Q3
3	2009Q3	2015Q3

Source: Author's compilation.

^a Significant at the 0.05 level.

^b Bai-Perron (Econometric Journal, 2003) critical values.

Table A5
Structural break test for GORTT energy revenue

Sequential F-statistic determined breaks:			
			3
Break Test	F-statistic	Scaled F-statistic	Critical Value ^b
0 vs. 1 ^a	87.25921	87.25921	8.58
1 vs. 2 ^a	162.0329	162.0329	10.13
2 vs. 3 ^a	27.21985	27.21985	11.14
3 vs. 4	1.183115	1.183115	11.83

Break dates:		
	Sequential	Repartition
1	2005Q3	2005Q3
2	2015Q4	2008Q3
3	2008Q3	2015Q3

Source: Author's compilation.

^a Significant at the 0.05 level.

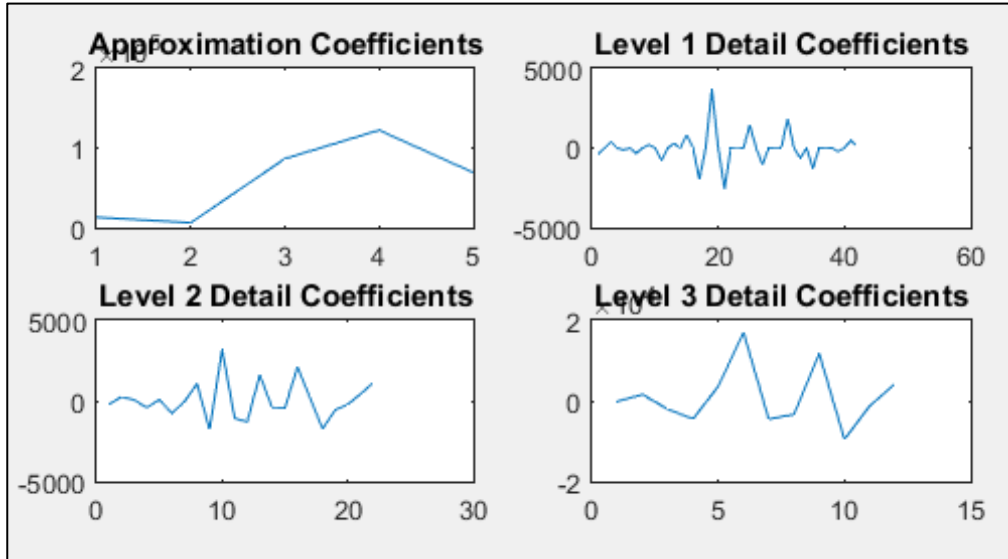
^b Bai-Perron (Econometric Journal, 2003) critical values.

The Bai-Perron structural break test is a right tailed test. The test statistic fell in the rejection region only when testing for 4 structural breaks. This suggested that there were 3 structural breaks. The results suggest that both GDP and the GORTT energy revenue have 3 structural breaks.

The presence of non-normality, non-stationarity, and non-linearity (as evidenced by the 3 structural breaks) suggests that traditional models based on those assumptions are not appropriate for modelling the relationship between GDP and the GORTT energy revenue. This provides further justification for the wavelet transform analysis.

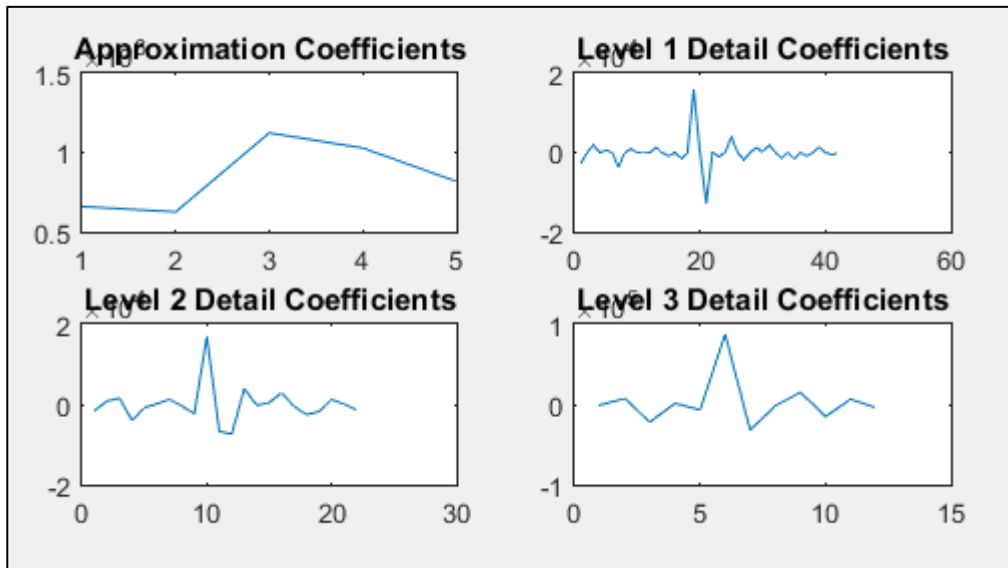
7. Results – wavelet transform analysis

Figure A1
Wavelet decomposition for the energy revenue (Daubechies 3 levels of detail)



Source: Author's compilation.
Note: 3 levels of detail were used, because when 4 or more levels of detail were used, it produced too few observations for the Granger causality test.

Figure A2
Wavelet decomposition for the GDP (Daubechies 3 levels of detail)



Source: Author's compilation.
Note: 3 levels of detail were used, because when 4 or more levels of detail were used, it produced too few observations for the Granger causality test.

As can be seen in table A6, there is strong positive dependence between the decompositions. This was observed for all the decompositions for both the correlation coefficient, and the copula. This suggests that Trinidad and Tobago's GDP is likely to move in the same direction as the GORTT's energy revenue. Therefore, growth in the GORTT's energy revenue would be accompanied by GDP growth. Likewise, contraction in the GORTT's energy revenue would be accompanied by contraction in the GDP. Indeed, this highlights the importance of the energy revenue to the economy of Trinidad and Tobago.

Table A6
Dependence between the energy revenue and the GDP at the decompositions

	D1	D2	D3
Correlation	0.859791	0.785405	0.801296
Copula	0.7061	0.7553	0.7220

Source: Author's compilation.

Table A7
Granger causality results

Granger Causality between D1 for GDP and Revenue			
Null Hypothesis:	Obs	F-Statistic	Prob.
REV does not Granger Cause GDP	40	5.90212	0.0062
GDP does not Granger Cause REV		2.48853	0.0976
Granger Causality between D2 for GDP and Revenue			
Null Hypothesis:	Obs	F-Statistic	Prob.
REV does not Granger Cause GDP	20	2.66362	0.1024
GDP does not Granger Cause REV		0.19446	0.8253
Granger-Causality D3 for GDP and Revenue			
Null Hypothesis:	Obs	F-Statistic	Prob.
GDP does not Granger Cause REV	10	0.03481	0.9660
REV does not Granger Cause GDP		0.27797	0.7683

Source: Author's compilation.

As can be seen in table A7 there was Granger causality between the energy revenue and the GDP. In fact, there was feedback causality between the energy revenue and the GDP. However, no causality was found at the 2nd and 3rd levels of detail. This non-existence of causality at the later details is a result of the non-linearity of the data. Moreover, it suggests that the causal link between the GDP and the GORTT energy revenue dies out over time. In other words, the energy revenue impact upon the real GDP is felt within 2-4 quarters, but dies out afterwards.

This results highlight that the effect of changes in the GORTT energy revenue is felt on the GDP within a short period of time (2-4 quarters). However, the effect is not permanent. This result is also plausible given that the energy revenue fluctuates, and it is used almost immediate to satisfy public finance commitments.

Annex 3

Estimated tax revenues under the 3 scenarios

Table A8
Estimated tax revenue

Year	Trinidad & Tobago gas production (Billion cubic metres)	Japan LNG prices (US\$ per mmbtu)	NBP prices (US\$ per mmbtu)	Tax at current circumstances (TT\$)	Tax at Japan prices (TT\$)	Tax at NBP (TT\$)
1999	11.7	\$3.14	\$1.86	\$1,172,588,803	\$1,839,434,657	\$1,092,156,246
2000	14.5	\$4.72	\$2.91	\$1,453,490,297	\$3,432,599,569	\$2,115,053,674
2001	15.5	\$4.64	\$3.67	\$1,544,458,397	\$3,581,338,160	\$2,831,809,261
2002	18.0	\$4.27	\$3.21	\$1,801,368,305	\$3,848,985,423	\$2,893,158,721
2003	26.3	\$4.77	\$4.06	\$2,633,076,646	\$6,278,807,020	\$5,349,303,220
2004	27.3	\$5.18	\$4.30	\$2,729,042,993	\$7,070,995,682	\$5,869,970,894
2005	31.0	\$6.05	\$5.83	\$3,096,913,990	\$9,364,616,673	\$9,027,996,691
2006	36.4	\$7.14	\$7.87	\$3,642,722,589	\$13,001,438,609	\$14,341,885,135
2007	39.0	\$7.73	\$7.99	\$3,899,632,497	\$15,072,294,298	\$15,586,833,040
2008	39.3	\$12.55	\$11.60	\$3,928,622,331	\$24,648,676,670	\$22,787,030,961
2009	38.9	\$9.06	\$8.53	\$3,888,636,353	\$17,611,902,713	\$16,587,680,263
2010	40.3	\$10.91	\$8.03	\$4,028,587,276	\$21,974,715,895	\$16,176,844,577
2011	38.7	\$14.73	\$10.49	\$3,868,643,364	\$28,491,221,430	\$20,293,510,376
2012	38.5	\$16.75	\$10.93	\$3,848,650,375	\$32,228,921,598	\$21,024,272,566
2013	38.7	\$16.17	\$10.73	\$3,868,643,364	\$31,276,796,146	\$20,748,129,635
2014	38.1	\$16.33	\$9.11	\$3,808,664,397	\$31,096,419,971	\$17,357,598,689
2015	36.0	\$10.31	\$6.72	\$3,598,738,013	\$18,543,144,563	\$12,090,113,985
2016	31.3	\$6.94	\$4.93	\$3,128,902,772	\$10,852,400,879	\$7,714,799,868
2017	31.9	\$8.10	\$5.62	\$3,188,881,739	\$12,907,205,522	\$8,957,953,403
2018	34.0	\$10.05	\$6.62	\$3,398,808,123	\$17,077,691,946	\$11,254,660,022
2019	34.6					

Source: Economic Commission for Latin America and the Caribbean (ECLAC) on the basis of official figures.



UNITED NATIONS

Series

ECLAC

Studies and Perspectives-The Caribbean

Issues published

A complete list as well as pdf files are available at
www.eclac.org/publicaciones

101. Navigating transfer pricing risk in the oil and gas sector: essential elements of a policy framework for Trinidad and Tobago and Guyana, Sheldon McLean, Don Charles and Antonio Rajkumar, (LC/TS.2021/10/Rev.1, LC/CAR/TS.2021/3/Rev.1), 2021.
100. Addressing the adverse impacts of non-communicable diseases on the sustainable development of Caribbean countries, Abdullahi Abdulkadri, Shirelle Floyd, Iskuhi Mkrtchyan, Gina Marajh, Candice Gonzales and Colette Cunningham-Myrie, (LC/TS.2021/4, LC/CAR/TS.2021/2), 2021.
99. Economic Survey of the Caribbean 2020: facing the challenge of COVID-19, Dillon Alleyne, Sheldon McLean, Michael Hendrickson, Hidenobu Tokuda, Machel Pantin, Nyasha Skerrette and Keron Victor, (LC/TS.2021/1, LC/CAR/TS.2021/1), 2021.
98. Advancing gender equality in environmental migration and disaster displacement in the Caribbean, Amelia Bleeker, Pablo Escribano, Candice Gonzales, Cristina Liberati and Briana Mawby, (LC/TS.2020/188, LC/CAR/TS.2020/8), 2020.
97. The case for financing: Caribbean resilience building in the face of the COVID-19 pandemic, Dillon Alleyne, Sheldon McLean, Abdullahi Abdulkadri, Catarina Camarinhas, Michael Hendrickson, Willard Phillips, Francis Jones, Hidenobu Tokuda, Machel Pantin and Nyasha Skerrette (LC/TS.2020/161, LC/CAR/TS.2020/7), 2020.
96. Statistical disclosure control for Caribbean census tables: a proposal to expand the availability of disaggregated census data, Francis Jones, (LC/TS.2020/159, LC/CAR/TS.2020/6), 2020.
95. Economic implications of the ban on single-use plastics in the Caribbean: a case study of Trinidad and Tobago, Willard Phillips, Elizabeth Thorne and Camille Roopnarine (LC/TS.2020/127, LC/CAR/TS.2020/5), 2020.
94. Creating an enabling environment for e-government and the protection of privacy rights in the Caribbean: a review of data protection legislation for alignment with the General Data Protection Regulation, Amelia Bleeker (LC/TS.2020/126, LC/CAR/TS.2020/4), 2020.
93. The use of technology and innovative approaches in disaster and risk management: a characterization of Caribbean countries' experience, Luciana Fontes de Meira, Omar Bello (LC/TS.2020/106, LC/CAR/TS.2020/3), 2020.
92. Preliminary overview of the economies of the Caribbean 2019–2020, Dillon Alleyne, Michael Hendrickson, Sheldon McLean, Maharouf Oyolola, Machel Pantin, Nyasha Skerrette and Hidenobu Tokuda (LC/TS.2020/56, LC/CAR/TS.2020/2), 2020.

STUDIES AND PERSPECTIVES

Issues published:

101. Navigating transfer pricing risk in the oil and gas sector
Essential elements of a policy framework for Trinidad and Tobago and Guyana
Sheldon McLean, Don Charles, Antonio Rajkumar,
100. Addressing the adverse impacts of non-communicable diseases on the sustainable development of Caribbean countries
Abdullahi Abdulkadri, Shirelle Floyd, Iskuhi Mkrtychyan, Gina Marajh, Candice Gonzales, Colette Cunningham-Myrie
99. Economic Survey of the Caribbean 2020
Facing the challenge of COVID-19
Dillon Alleyne, Sheldon McLean, Michael Hendrickson, Hidenobu Tokuda, Machel Pantin, Nyasha Skerrette, Keron Victor

