Policy Brief
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Natural Resource Governance Institute

Lessons for Generating Government Revenue for New and Prospective Liquefied Natural Gas Producers

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Key messages

- The market for liquefied natural gas (LNG) is changing fast, with increasing demand, new sources of supply, and a growing spot market. Over the last decade (2008 to 2018), LNG prices in the three main markets of North America, Western Europe and East Asia have diverged significantly at times, creating arbitrage opportunities for sellers.
- Trinidad and Tobago and Peru offer two examples of developing countries that faced challenges in maximizing government revenue from LNG sales during that time. Although LNG markets are evolving, these examples offer lessons for new and prospective LNG producers, especially in Sub-Saharan Africa.
- A key area (and the focus of this briefing) is the valuation of LNG sales and the corresponding impact on government revenues.
- Governments should pay close attention to LNG project structure and the long-term LNG sale and purchase agreements between LNG producers and offtakers, especially when they are related companies. Governments should push for these agreements to maximize the price flowing back to the LNG plant and the upstream producer and should favor project structures that facilitate this.
- In particular, the practice of diverting LNG cargos to more lucrative export markets than the ones initially designated in offtake agreements should be regulated and monitored by governments to balance the financial incentives to LNG sellers with the interests of LNG-exporting countries. This will become increasingly important as the market becomes more liquid and sellers have more options.

INTRODUCTION

Most natural gas is transported from production sites to consumers through extensive networks of pipelines. Given the distance between gas resources and markets, not all gas can be piped directly to consumers, and LNG technology allows the transport of natural gas over long distances.[1] The market for liquefied natural gas (LNG) has increased in the last two decades, led by strong demand for a resource that is less polluting than coal for power generation. It is also expected to grow significantly more in the next two decades, as it can play a strong complementary role to renewables in the electricity system.[2] (See figure 1.) LNG has become a key export commodity for many countries, including developing economies. Many

1 International Gas Union, *Natural Gas Facts & Figures*, accessed 6 November 2019, www.igu.org/resources-data.
2 John Kemp. *Natural gas and the global energy transition History and Outlook*, (Thomson Reuters, 2019), fingfx.thomsonreuters.com/gfx/ce/7/6939/6921/NATURAL GAS AND ENERGY TRANSITION.pdf.

others have prospective gas resources and plans to build LNG plants, including Senegal and Mauritania in West Africa and Mozambique and Tanzania in East Africa.[3,4]

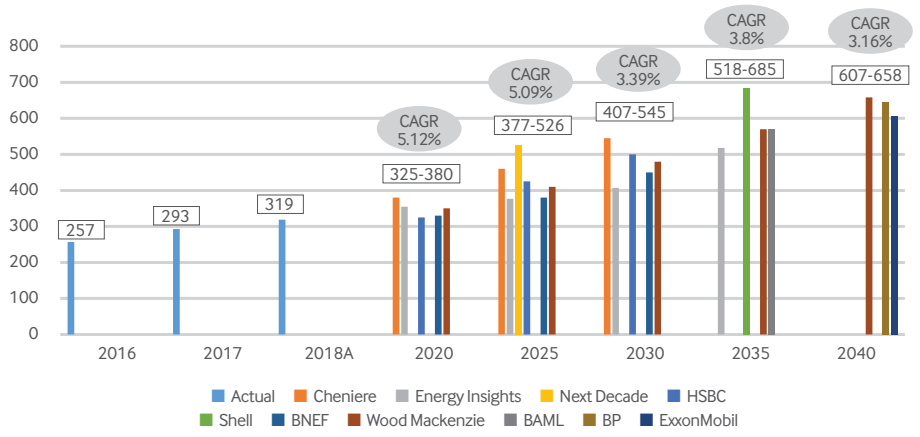


Figure 1. Current and planned global LNG demand[5]

Countries that export LNG will collect revenue from the LNG value chain, described in figure 2, depending on different commercial structures. In all cases, the government allocates rights to extract gas to a company, which then extracts the natural gas and sells or transfers it to an LNG liquefaction plant through a domestic pipeline network. The plant then liquefies the natural gas and the LNG is sold to an offtaker who delivers the LNG cargos via special ships to a regasification terminal which turns the LNG back into gas for delivery to the final consumer. There are three main types of commercial arrangements, as well as hybrid ones, that have implications for how governments may collect revenue:[6]

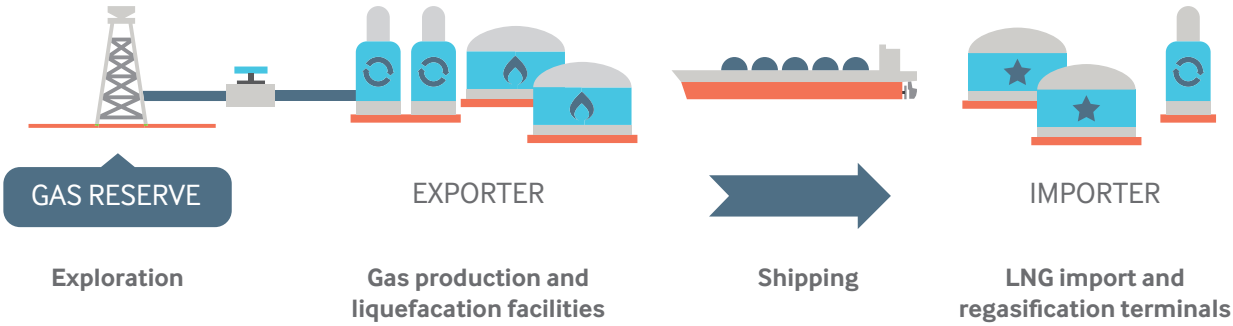
1. **Integrated commercial structure.** The same company, or consortium of companies, owns all segments of the value chain from upstream gas production facilities to the LNG plant, as well as the gas produced and liquefied.
2. **Merchant structure.** Different companies own the upstream licenses and the LNG plant, and negotiate a price for the "feed gas" sold to the plant, under a long-term sale and purchase agreement. The plant takes ownership of the gas it purchases from upstream suppliers and sells it to customers.
3. **Tolling structure.** The LNG plant is only a pass-through, charging a fee for each unit of gas it receives from upstream suppliers, who keep ownership of the gas after it is processed into LNG.

Depending on the structure, the government can choose to generate revenue by collecting royalties on the value of gas production at the wellhead, income taxes on any element of the domestic part of the value chain (extraction, transport, liquefaction) and/or by taking a direct ownership in either or both extraction and liquefaction. The fiscal regime can end up being very different for different

3 Paul Melly, "Senegal and Mauritania projects make headway," *Petroleum Economist*, 26 February 2019, www.petroleum-economist.com/articles/upstream/exploration-production/2019/senegal-and-mauritania-projects-make-headway.
4 David Ledesma, "East Africa Gas – The Potential for Export," *Oxford Institute for Energy Studies* (March 2013), www.oxfordenergy.org/publications/east-africa-gas-the-potential-for-export/.
5 Standard Bank, "Rovuma LNG Macroeconomic study," downloaded 18 October 2019, www.standardbank.co.mz/en/content/download/94419/2328909/file/Complete Standard Bank Rovuma LNG study.pdf.
6 U.S. Department of Energy, "Global LNG Fundamentals," 2017, www.energy.gov/sites/prod/files/2017/10/f37/Global LNG Fundamentals_0.pdf.

segments of the value chain, and government revenues are more susceptible to structures where upstream producers and LNG owners share economic interests and can price gas to move value to the least taxed segments of the value chain. Moreover, in all commercial structures, government revenues will depend to different degrees, on the ultimate sale value of LNG, which determines the gross revenue of LNG plants and their suppliers.

Figure 2. The LNG value chain[7]



A key element of the sale value of LNG is the market destination of cargos. Unlike oil, there is currently no common global benchmark for LNG prices. Instead, there are three main markets, with different pricing mechanisms.[8] In North America, the relevant price is the Henry Hub price, based in Louisiana, in the United States. The European gas market is dominated by imports of piped gas from Russia, Central Asia and North Africa, but with a growing role for LNG imports in balancing peak demand. There are different price references for different countries, which are all interlinked and depend on the opportunity cost of alternative resources. The Title Transfer Facility (TTF), the virtual trading hub for the Netherlands' natural gas market, has become the most used hub pricing in Europe by traders for both pipeline gas and LNG.[9] East Asia is the biggest and fastest growing market for LNG, with no single official benchmark, and gas prices traditionally linked to the price of oil. The prices to the biggest importers, Japan and Korea, tend to be a reference for that regional market, through the Japan/Korea Marker (JKM), although there is a range of LNG prices for different buyers, depending on specific purchase agreements.

Figure 3 shows how these different natural gas prices have diverged at times over the last 10 years. North American prices have been depressed by the rapid increase of low-cost natural gas from shale deposits, while European and especially Asian prices have stayed more closely aligned with the price of oil and up to two or three times the Henry Hub price.

7 International Gas Union, 2019.
8 Oxford Institute for Energy Studies, "Quarterly Gas Review," June 2019, globalnghub.com/wp-content/uploads/2019/06/Quarterly-Gas-Review-6.pdf.
9 Gregor Spilker, "A Story of Success: The Evolution of TTF Trading," CME Group, www.cmegroup.com/education/articles-and-reports/a-story-of-success-the-evolution-of-ttf-trading.html.

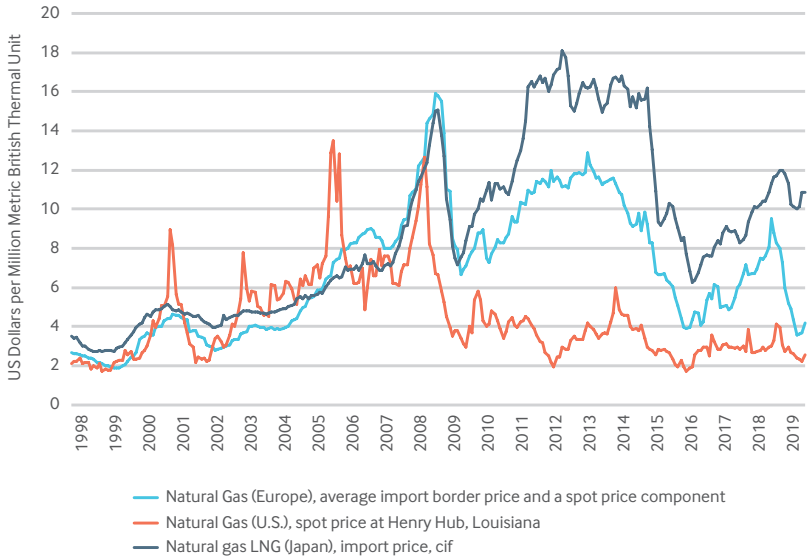


Figure 3. Natural gas prices 1998-2019[10]

In a more liquid commodity market like gold, copper or oil, the law of supply and demand would work more smoothly, and such price differences could not persist. Sellers would supply the markets where prices are highest, slowly reducing demand and prices, with the opposite effects in markets with lower prices, until prices equalized. However, LNG prices have been stickier, for two main reasons. First, only a handful of countries in the world produce and export LNG. They tend to be located far from the markets with the highest demand, which leads to higher transport costs and greater transport inefficiencies due to a higher rate of evaporated LNG losses. Second, most of the trade is based on long-term contracts, which are the basis for long-term investment in LNG capacity. In these long-term contracts, or sale and purchase agreements, the main objective of producers is to secure stable revenue to back up the initial investments. Buyers would commit to purchasing large quantities of LNG every year, often under "take-or-pay provisions," which means they have to pay the seller even if they do not need the gas, at a price pre-determined, typically in reference to the regional price of gas of the buyer.

That situation may change in the future. Three factors—a growing supplier base of LNG, including the US, Australia and possibly several African countries, increasing demand, and the rapid development of LNG facilities needed to purchase and use LNG (i.e. regasification terminals, storage, pipeline networks)—may cause the market to become more liquid, as there will be fewer incentives to commit to long-term contractual prices. Already in 2018, some buyers in Asia were starting to base some of their contracts on Henry hub rather than oil prices, and spot trades of LNG represented 32 percent of global LNG imports.[11,12]

In the meantime, an important feature of the LNG market is destination flexibility, also called "diversions" of cargo. Through diversions, LNG buyers, or offtakers, can sell LNG to other markets than the one intended when they signed a long-term purchase agreement. This option is important for buyers under a strict take-or-pay contract, so that they can respond to a lack of demand in their main market, deliver the gas where it is needed, and avoid being left with unsold supplies. It has also been used by offtakers to maximize their revenue since regional prices started diverging substantially.

10 Indexmundi, *Commodities*, accessed 22 July 2019, www.indexmundi.com/commodities/.
11 International Gas Union, 2019.
12 Emiko Terazono, "Looser restrictions prompt surge in LNG liquidity," *Financial Times*, 1 April 2019, www.ft.com/content/e21ec520-523b-11e9-b401-8d9ef1626294.

Producing countries had not necessarily foreseen this scenario, which created the risk that producers and host governments may not share in the upside of such diversions happening beyond their jurisdictions. The following case studies from the Americas illustrate the challenges posed by revenue risks from diversion of LNG sales, and some of the possible policy responses.

The Latin America and Caribbean region is outside the three main regional gas markets and has not been a major player in any of them. Only two countries in the region currently export LNG, Peru and Trinidad and Tobago, although others such as Argentina and Brazil may join in the future. Trinidad and Tobago built a LNG plant with a first train (i.e., a liquefaction and purification facility) in 1999, and since 2005 hosts four trains with a current capacity of 15 million tons per annum. Peru built its single-train LNG plant between 2006 and 2010 and now exports up to 4.4 million tons per annum. The two countries' exports amount to 5 percent and 1.5 percent of the global market respectively. In both cases, LNG sales have been based on long-term contracts with prices linked to the North American gas market, and over the last decade the two countries failed to benefit from higher LNG prices in other regional markets. In this note, we review the mechanisms through which companies sold LNG at suboptimal prices, how Trinidad and Peru lost government revenue as a result, and how new producers in the growing LNG market could avoid similar losses in the future.

TRINIDAD AND TOBAGO

In Trinidad and Tobago, natural gas for export is either sold to the LNG plant Atlantic LNG (ALNG) for liquefaction and export as LNG, or to the state-owned National Gas Company (NGC) for distribution to the downstream sector, including to plants making ammonia or methanol for export, and domestic energy generation. Gas sales to ALNG represent about 55 percent of total gas production, and sales to petrochemical operations about 30 percent.[13] (See figure 4.)

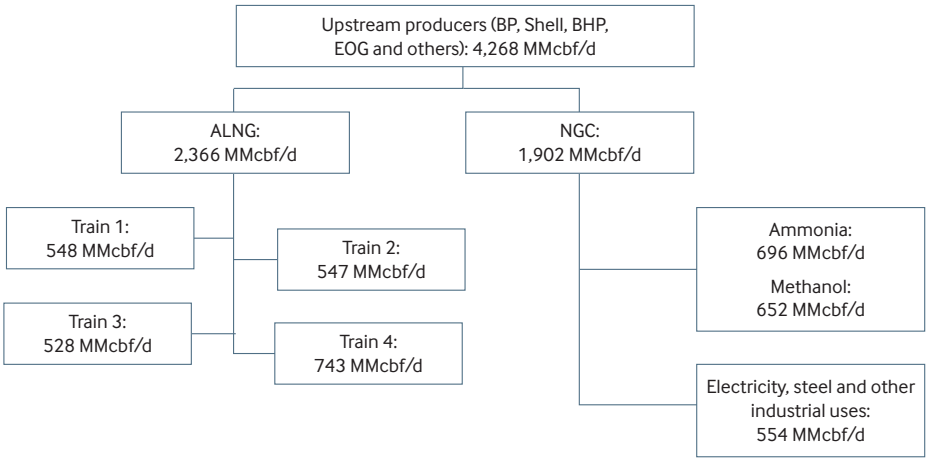


Figure 4. Natural gas production and destination in Trinidad and Tobago (maximum capacity)[14]

In Trinidad and Tobago, only the model upstream contracts are available, as well as licenses kept in a public register by the Minister of Petroleum, which according to article 3 of Petroleum Regulations should also include licenses for liquefaction,

13 This section draws heavily on the following presentation to the parliament of Trinidad and Tobago: Poten and Partners, Value Generation in the Gas Sector, March 2018, www.energy.gov.tt/spotlight-on-energy-feature-presentations/ (2018) and full report Poten and Partners, *Trinidad and Tobago: Gas Master Plan*, September 2015, parlcloud.ttparliament.org:8080/paperslaiddownloader/Default.aspx?path=DocumentsPapersLaid/Eleventh Parliament/Second Session, Eleventh Parliament/The Trinidad and Tobago Gas Master Plan - Final Report.pdf

14 Anthony Paul, presentation to NRGI, May 2018.

shipping, marketing and trading.[15,16] The full text of upstream resource contracts and contracts between upstream and downstream operators are not public, so we do not know the exact terms of the gas sales.[17] But estimated netback prices in figure 5 show that, over the last ten years, the gas sold to ANLG has provided much lower returns than the gas used for ammonia and methanol productions. These netback prices are estimated prices at the time when the gas reached the plant, based on final sale prices to the market of destination minus all costs incurred after the production stage, such as processing and transport. ALNG has relatively low costs of production, as it was built when LNG plant costs were still low and by now the initial investment has been fully amortized.

The prices of ALNG's sales matter for government revenues in two ways. First, any profit made by the plant is taxed, and NGC receives dividends from the trains in which it holds equity.[18] Second, the price of the "feed gas" supplied by upstream producers to ALNG depends on the realized LNG prices. So upstream taxation is also impacted by LNG netback prices.[19] Upstream taxation in Trinidad and Tobago is divided in two main regimes, production licenses and production sharing contracts (PSCs). Since 1996, the government has awarded petroleum licenses exclusively on the basis of PSCs. Under production licenses, the government collects a progressive royalty on gross revenue, and a petroleum profit tax, whose rates vary for different types of projects. Under PSCs, government upstream revenue almost exclusively comes from the state share of profit oil/profit gas, after deduction of allowable development and operating costs incurred by contractors. Royalties and income taxes applicable to the sector are paid out of the government's share of profit gas. Low netback gas prices mean that upstream gas producers in Trinidad and Tobago earn relatively little in gross revenue and even less in profits, which would affect government revenues both under production licenses and PSCs.

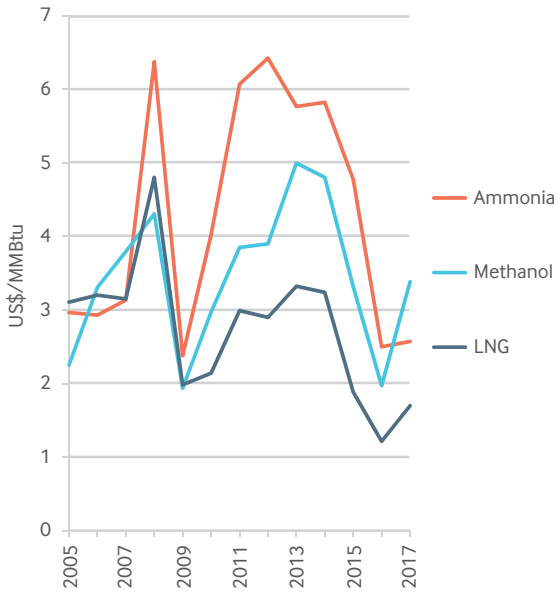


Figure 5. Estimated netback pricing to Plant Inlet*[20]

15 Ministry of Energy and Energy Industries, Government of Trinidad and Tobago, *Model Contracts*, accessed 7 November 2019, www.energy.gov.tt/model-contracts/.
16 Ministry of Energy and Energy Industries, Government of Trinidad and Tobago, *License Registers*, accessed 7 November 2019, www.energy.gov.tt/services/license-registers/.
17 Curtis Williams, "Wanted: Greater transparency," *Trinidad and Tobago Guardian*, 20 September 2018, www.guardian.co.tt/business/wanted-greater-transparency-6.2.671239.7c3f3dfebd.
18 The main corporate taxes are summarized in PWC, *Trinidad and Tobago Corporate Taxes*, accessed 22 July 2019, taxsummaries.pwc.com/ID/Trinidad-and-Tobago-Corporate-Taxes-on-corporate-income.
19 Poten, 2015.
20 Poten, 2018.

Low netback prices for ALNG may reflect low LNG prices to its customers. Indeed, ALNG's production has been sold mostly based on Henry Hub prices, following the terms of offtake agreements signed before the boom in US shale extraction and the depression of North American LNG prices. But the country's offtake agreement terms vary for the production of different trains of ANLG, with various impacts on netback prices and hence government revenues, as described in the table below.

Table 1. Summary of pricing mechanisms for the offtake of LNG production in Trains 1,2 ,3 and 4[21]

	Feed gas suppliers	Plant owners	Offtaker	Share of production	Pricing mechanism
Train 1	BPTT (BP 70%, Repsol 30%)	ALNG Co: BP 34%, Shell 46%, NGC TT LNG 10%, China Investment Corp 10%	Engie (formerly GDF Suez) takes 60% of the production	60%	Henry Hub-based price but the upside of any diversion shared with ALNG
			Gas Natural (formerly Enagas) 40%.	40%	After several legal disputes, Gas Natural now uses an Atlantic basin price that reflects the market prices in both Europe and North America, its main customers, and the upside of any diversion outside of the Atlantic basin is shared with ALNG.
Train 2	BPTT (~50%)	BP: 42.5%, Shell 57.5%	Gas Natural	21%	Indexed to fuel oil benchmarks, with no diversion restrictions or upside sharing
			Shell	20%	Indexed to Spanish power prices, with no diversion restrictions or upside sharing
			BP	any excess volume	Sold to BP Gas Marketing based on Henry Hub pricing with 50/50 diversion upside sharing
	NECMA (~50%)		Engie	11%	Henry Hub-based price but shares the upside of any diversion with ALNG
			PFLE	48%	Henry Hub-based price with a 50/50 diversion upside sharing
Train 3	BPTT (~75%)	BP: 42.5%, Shell 57.5%	Shell	48%	Indexed to Spanish power prices, with no diversion restrictions or upside sharing
	ECMA (~16%)		Naturgas Energia	26%	Indexed to the Brent with no diversion restrictions or upside sharing
			Trinling	17%	Henry Hub-based price with a 50/50 diversion upside sharing
	NCMA (~9%)		PFLE	9%	Henry Hub-based price with a 50/50 diversion upside sharing
			BP	any excess volume	Sold to BP Gas Marketing based on Henry Hub pricing with 50/50 diversion upside sharing
Train 4	BPTT (~69%)	BP 37.8%, Shell 51.1%, NGC 11.1%	BP	37.8%	Marketing affiliates buy LNG at free on board (FOB) prices based on Henry Hub prices for US exports and use complex pricing arrangements for cargos diverted to other markets, with a 50/50 split for incremental revenue net of cost between the LNG supplier and the marking entities. But the government does not have the right to audit these arrangements
	ECMA (~19%)		Shell	51.1%	
	NCMA (~4%)				
	CB (~5%)				
	EOG (~3%)		NGC	11%	NGC markets some of its LNG itself, and through BP for the rest.

21 Poten, 2015. Some of these mechanisms have been renegotiated since, as discussed below.

Assessing contract outcomes *ex-post* can be misleading. When LNG purchase agreements were signed, the parties did not know how the gas markets would evolve. Trinidad and Tobago may not have received as much value from LNG sales as it could, but it does not necessarily mean the purchase agreements were unbalanced. However, several pricing mechanisms in LNG sales contracts did conflict with provisions from the 1974 Petroleum Taxes Act addressing petroleum sales, as detailed below. With ex-post information, it is constructive to analyze where value has been lost in the past and how contract terms could be improved, particularly with an eye to lessons for new LNG producers.

First, the ownership structure of the value chain matters. As figure 6 shows, realized contract prices were lower for train 4, and higher for train 1. Train 4, although formally a tolling structure, has a perfectly integrated ownership where the same shareholders, BP, Shell (formerly BG) and NGC, produce the gas that feeds into the plant, and get an equivalent percentage of the LNG offtake. Through gas transfer prices they can shift significant value from the upstream and plant to the offtakers. This would have benefited Trinidad and Tobago through the 11 percent interest of NGC, but on balance the government revenue lost from the loss of value in the upstream and the plant has been higher.[22] Trains 2 and 3 follow a more traditional tolling structure, and while Shell has the largest interests in the whole value chain, it has not been a perfect pass-through. This may factor into why the Shell offtake for those trains has no diversion restrictions or upside sharing. The plant owners for train 1, on the other hand, are distinct from the offtakers, and have therefore a stronger incentive to maximize LNG sale prices. Therefore, integrated ownership structures such as that used for train 4, in which shareholders have clear interest in, and limited obstacles to, transferring profits as far as possible down the value chain, outside of the country's taxation rights, require more vigilance from the government.

Second, the ownership structure also determines how much revenue flows back to the upstream producer, which is subject to a higher government take than ALNG. For instance, BPTT receives 53 percent of LNG sales revenues from train 1, while suppliers to trains 2 and 3 receive about 70 percent, corresponding to LNG sales revenues after deduction of a tolling fee. [23]

Third, some contracts allow diversion to different markets without any provision to share the upside with the LNG plant or the upstream producer, and by extension the government. This is the most damaging when the base price is based on the lowest global index, the Henry Hub, as with the sales to Shell from trains 2 and 3.

Fourth, even when contracts include profit-sharing arrangements for diversions, offtakers would rather use ALNG production to fill demand from the customers to which they are bound at low prices, and prefer to sell to more expensive markets, or on the sport market, the LNG that they can divert without having to share the upside with gas suppliers. This is why Shell would rationally choose to sell its train 4 production to Atlantic basin destinations, and divert sales from trains 2 and 3 to more lucrative markets. Poten also indicated that Shell and BP in their role as commodity traders, marketing the production from Petrotrin's share in train 2 (through PFLE consortium) and NGC in train 4, respectively, may be consistently selling these cargos at the lowest price in their portfolios.[24]

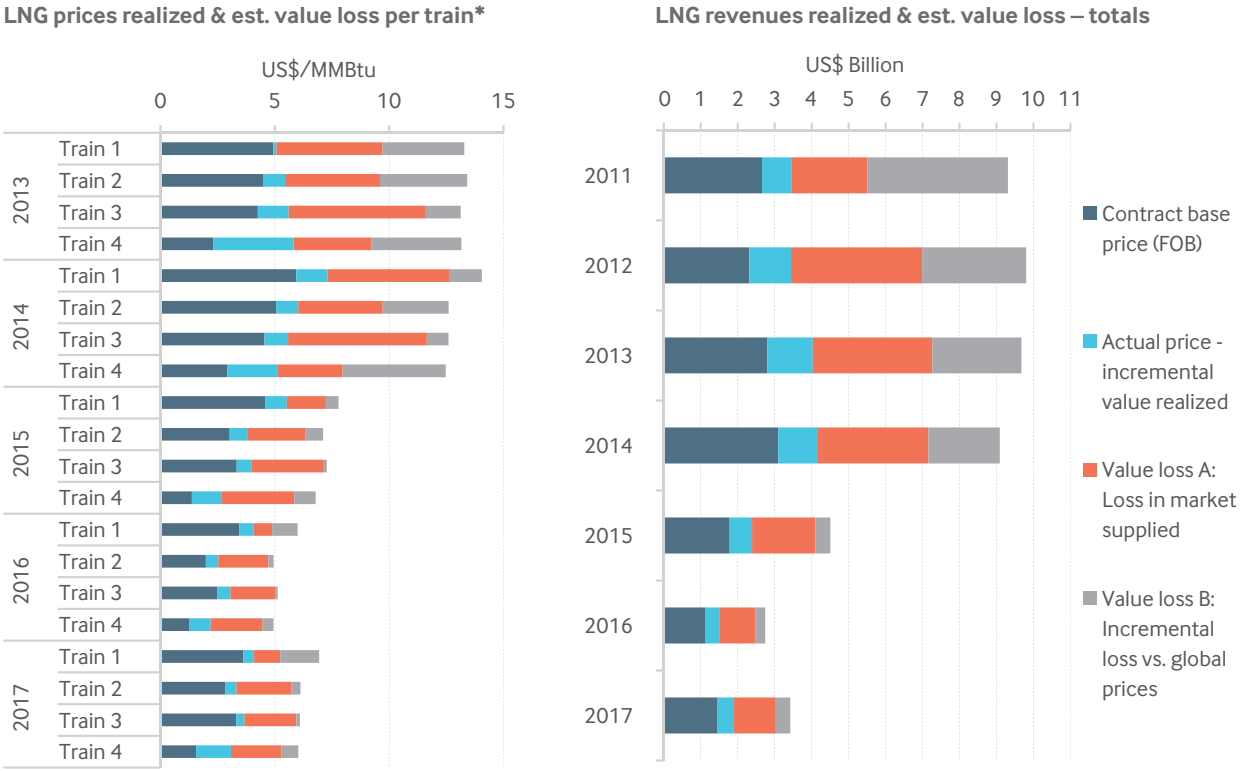
22 Poten, 2015.
23 *Ibid.*
24 *Ibid.*

Fifth, some of the formulas to share the upside of diverted sales may not be balanced.[25] From the information available through the Poten report, an equal 50/50 split seems to be a common practice in Trinidad and Tobago, when contracts include profit-sharing arrangements. But in the case of diverted cargo sales from train 4, various costs can be deducted from increased revenue, with little oversight from ALNG or the government, so that the actual share from the upside to the supplier may be very small.

Finally, offtakers may not always accurately declare the final destination of their LNG sales, using marketing arrangements or even unloading and reloading LNG cargos to mask the identity of the final customer, as Poten reported.

Poten estimated the potential value lost by Trinidad and Tobago from LNG sales, comparing contract prices first with actual prices, and then with the potential prices that could have been achieved. "Value Loss A" in figure 6 represents the value lost by selling LNG in a given market (country) at prices lower than the prevailing price in that market. It is a more realistic benchmark than "Value Loss B," which is based on the hypothetical scenario of selling LNG to alternative markets at the higher global spot price. But "Value Loss A" still represents billions of US dollars.

Figure 6. Poten's estimates of value loss per train, Trinidad and Tobago, 2013-2017[26]



** Value loss A: Difference between the price realized from the market actually supplied and Poten's estimate of the prevailing price in that market*
Value loss B: Poten's estimate of the incremental price that could have potentially been realized by selling FOB at an oil-linked price (11.5 – 12%)

25 There are different diversion provisions applied in the sector, not all of them allowed by all jurisdictions. See Steven P. Finizio, "Destination Restrictions and Diversion Provisions in LNG Sale and Purchase Agreements," *The Guide to Energy Arbitrations - Second Edition* (UK, Law Business Research Ltd, 2017), globalarbitrationreview.com/chapter/1142624/destination-restrictions-and-diversion-provisions-in-lng-sale-and-purchase-agreements.

26 Poten, 2018.

Trinidad and Tobago's Petroleum Taxes Act could have prevented some of the value loss. Article 5 of the 1974 legislation states that "the prices of crude oil, natural gas, petroleum products and petrochemicals is the actual realized price in a sale transaction at arm's length."[27] Further, the 1974 legislation clarifies what constitutes non-arm's length sales and authorizes the government to "substitute for the price reported the fair market value as determined by the Minister." The law was initially passed before LNG became an important feature of the gas market, but contractual provisions that stipulate a Henry Hub price regardless of the final destination of cargo would have violated the actual realized price principle. A 2006 amendment then extended the scope of article 5 to account for the specificities of the LNG trade that had developed since the law was passed. It empowered the tax administration, chaired by the Board of Inland Revenue, to inspect "any contract which [the taxpayer] entered into or proposes to enter into in respect of the sale, exchange, transfer or other disposition, for export purposes, of natural gas" and determine fair market value. The law also created a "Petroleum Pricing Committee consisting of public officers drawn from the Ministry of Finance, the Board of Inland Revenue and the Ministry of Energy and Energy-based Industries" to help making such assessments. These provisions should have empowered the government to scrutinize LNG sales from the different trains between private parties, whether related or not, granting a permanent right to audit sales that some contracts attempted to limit.

According to experts, the Petroleum Pricing Committee remained inactive for most of the past 15 years, and amid a general petroleum price boom, the government had little incentive to implement the full extent of the law. According to the Minister of Energy and Energy Industries, the committee has been reinstituted as part of a package of reforms to strengthen the regulation of the gas sector.[28]

Following the release of the Poten report and a "Spotlight on Energy," a public debate on energy organized in March 2018, the government embarked on a renegotiation of the terms of contracts with train 1 investors, and on a number of other terms in its relationship to Shell regarding trains 2, 3 and 4. A key outcome is the agreement on a new pricing formula for train 1 sales that could become the template for all LNG exports. The so-called train FOB 1 price is comprised of one-third Brent, one-third UK NBP (National Balancing Point) and one-third JKM (the Asian LNG Market price as set by Japan Korea Marker), based on a formula that also fixes regasification and shipping costs.[29] This new price formula still leaves room for offtakers to arbitrage between different markets, but ensures ALNG train 1 a much higher average price for its production. It should also be easier for the government to enforce, as it does not require a strict monitoring of the actual destination of each cargo.

27 Government of Trinidad and Tobago, *Petroleum Taxes Act*, updated to 31 December 2012, www.energy.gov.tt/for-investors/legislation-and-tax-laws/.

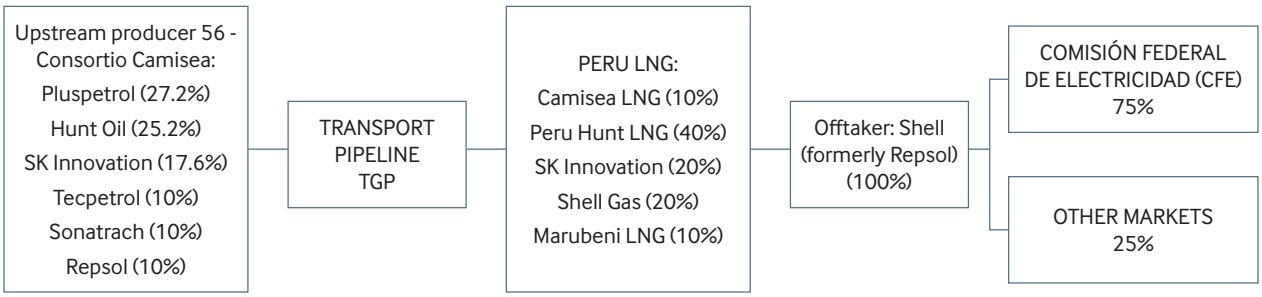
28 Minister Of Energy and Energy Industries Hon Franklin Khan, speech to Society of Petroleum Engineers of Trinidad and Tobago, 2018 *Energy resources conference*, 25 June 2019, accessed 22 July 2019 from the website of the Office of the Energy Ministry: www.energy.gov.tt/wp-content/uploads/2018/06/Senator-the-Honourable-Franklin-Khan-speech-at-the-Society-of-Petroleum-Engineers-of-Trinidad-and-Tobago-2018-Energy-Resources-Conference.pdf.

29 Minister Of Energy and Energy Industries Hon Franklin Khan, speech to Parliament, *Update on government strengthening of the energy sector*, 11 June 2019, accessed 22 July 2019 from the website of the Office of the Prime Minister of Trinidad and Tobago, www.opm.gov.tt/update-on-governments-strengthening-of-the-energy-sector/.

PERU

In Peru, Consortio Camisea extracts natural gas and natural gas liquids from blocks 56 and 88 of the Camisea field. Consortio Camisea sells natural gas from block 56 to Peru LNG through an 18-year Natural Gas Supply Agreement signed in 2006. Peru LNG then sells its entire production of LNG to Shell (formerly Repsol), under a long-term LNG sale and purchase agreement that runs until 2028. [30] Each segment of the value chain as describe in figure 7 is controlled by a different entity, although some companies have interests in multiple entities. Shell, formerly Repsol, is the only offtaker for the whole production of Peru LNG. It sells 75 percent of the LNG offtake to the Mexican electricity commission and delivers it to Manzanillo, a regasification plant on the Pacific coast, under a 15-year agreement that runs from 2011 to 2026, with a possible five-year extension. Shell sells the remaining 25 percent on the international spot market.[31]

Figure 7. LNG value chain and ownership in Peru [32]



The terms of the long-term LNG sale and purchase agreement between Peru LNG and Shell (formerly Repsol) are not disclosed, but Peru LNG's financial statements includes its sales, costs and profits. Peru LNG is subject to income tax in Peru; according to its financial statements, since it started its operations, it only paid income tax in 2017, for a total of 1.9 million USD.[33]

The Natural Gas Supply Agreement determines how much the Consortio Camisea collects from the gas sold to Peru LNG, by linking the price at which the offtaker (Shell) sells the LNG, called the sale price or reference value, with the contract price under the supply agreement. Figure 8 from Campodonico (2018) shows how the contract price is calculated for a large range of LNG prices, and compares it with what the netback price of gas would be, based on a fixed cost assumption of 2.89 USD/MMBtu. The figure shows that the contract price is almost always lower than what the netback price would be, and that the higher the value of LNG sales, the larger the difference between the two.

30 Block 88 production is sold domestically.

31 This section draws heavily from Humberto Campodónico Sánchez, *El gran fraude de la exportación de gas,* Serie Perú Hoy Nº 33 / Julio 2018: www.desco.org.pe/recursos/site/files/CONTENIDO/1220/15_Campodonico_PHj18.pdf and market information, for example from bond risk analyses such as Apoyo y Asociados, *Bonos Corporativos Perú LNG (PLNG) Informe Semestral,* 2 November 2017, www.aai.com.pe/wp-content/uploads/2017/11/PLNG-Set-17.pdf.

32 Humberto Campodonico, *presentation to NRGI*, May 2018.

33 Peru LNG, *Publications,* accessed on 7 November 2019, perulng.com/en/comunicaciones/publicaciones/categoria/reportes/.

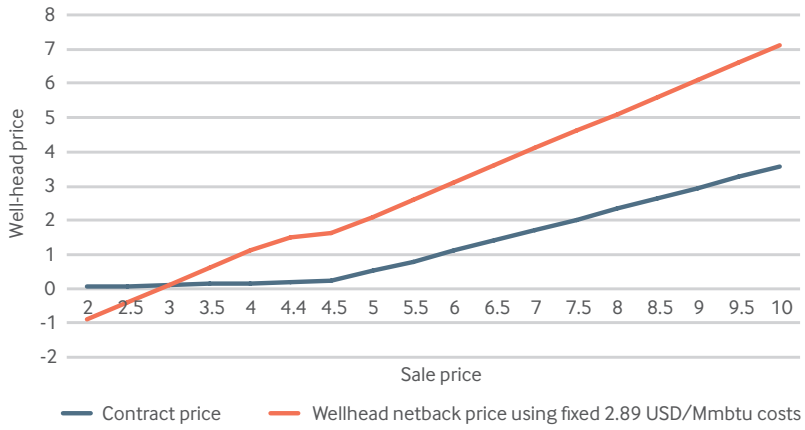


Figure 8. Wellhead price as a function of LNG sale price[34]

Consortio Camisea's revenue is subject to upstream taxation, including a royalty on production and a tax on profits. The price at which Shell sells the LNG offtake determines the returns of both the LNG plant and the upstream consortium at block 56, and therefore the amount of revenue the government collects from these privately-owned ventures through taxes on profits and royalties at the wellhead. The 75 percent of LNG production sold to the Mexican electricity commission is sold under a fixed formula of 91 percent of Henry Hub prices. The remaining 25 percent can be sold to more lucrative markets.

Peru may have lost value from its natural gas exported as LNG through several channels. First, Repsol and then Shell did not disclose the final destination of all of their cargos sold on the spot market. The Peruvian government took Consortio Camisea to arbitration for underestimating their gas sales from block 56 and collected 62 million USD as a result. This amount was based on the amount of royalties lost as a result of the underestimation of sales.[35] If sales were underestimated, the government may also have lost income tax.

Second, the gas contract price is not sufficiently linked to the LNG price achieved by the offtaker. It is biased in favor of the LNG offtaker, especially at higher LNG sale prices, as when the customers are located in the more lucrative markets of East Asia or Western Europe. This would have also affected the collection of royalties; Campodonico (2018) estimates that the Peruvian government would have collected 2.1 billion USD of royalties between 2011 and 2017, instead of the 1.04 billion USD it actually collected, if the royalty was based on a netback price calculated off of the actual LNG price achieved by Shell. This estimate is likely to be a minimum, as it does not include the associated tax on corporate income that would have been collected under higher netback prices to the upstream. Estimating the lost income tax that should have been collected by the tax authorities from Consortio Camisea is unfortunately not possible without further information on the costs and fiscal terms of the upstream project.

Third, 75 percent of LNG sales are committed and sold at very low prices, to the least attractive market. Mexico gets plenty of cheap gas from the United States, so its default price for LNG is the Henry Hub index. This has resulted in very low revenue to Peru LNG and in turn Consortio Camisea (for block 56), and therefore little to no income tax collection.

34 Campodónico, 2018.
35 Humberto Campodónico Sánchez, "Lecciones del triunfo de Perupetro en el CIADI," *Cristal de Mira*, 15 June 2015, www.cristaldemira.com/articulos.php?id=2520.

When Shell's LNG sale and purchase agreement with Mexico expires, Shell and the other shareholders of Peru LNG could instead try to find long-term customers in East Asia, or increase the percentage of production sold on the spot market. During the 2016 Peruvian presidential campaign, candidates proposed an earlier renegotiation of the LNG export contract, but the winning party never went through with their proposal.[36] Without an equity stake in the LNG plant or an offtaker role, the Peruvian government is not likely to be directly involved in any future negotiations. But the relevant regulatory body could require the company to demonstrate that it is taking the necessary steps to increase the total value generated from the sale of its LNG to offtakers.

Owning equity along the LNG value chain has its pros and cons. Without equity, Peru limited the losses it incurred in the sector to lower taxes and royalties from the upstream gas producer and lower taxes from the LNG producer due to lower than ideal prices or LNG exports. With an equity stake in the different segments of the value chain based in Peru, the country would have had investment costs and could also have lost value as a result of low returns to shareholders from these activities. But the government or its state-owned companies may have been in a better position to secure the country's interests and limit the leakages described above if they held equity in the project or more proactively regulated and monitored the sector.

LESSONS LEARNED

These two case studies offer some lessons on the relationship between LNG exports and generating public revenues. As the LNG market grows and more countries become exporters, these early lessons from developing countries may offer some insights to new producers:

- For LNG production that is sold through long-term offtake agreements, governments should require that the agreements contain rules that:
    - ensure that the netback price to the producer, and its incorporation in the calculation of royalties and income taxes, takes into account the final destination of LNG cargos and allows only arm's length cost deductions
    - provide for a periodic review of the pricing mechanism and/or price reopener triggers
    - encourage the offtaker to seek the buyer offering the highest possible price, allowing diversion of LNG cargos to different markets but also including a profit-sharing mechanism that aligns the incentives of the offtaker with the interest of the producer[37,38]
- Governments could go further to take advantage of the growing trend toward flexibility of the LNG market. Signing offtake agreements with large multinational companies or commodity traders may still be needed to secure financing, but maybe not for the entire production of LNG. For instance, governments could require LNG producers to organize competitive tenders for at least some volumes of LNG. If the plant is only a "tolling" pass-through, then

36 Alonso Hidalgo, Fernando Patzy and Kaisa Toroskainen, *Case study: Peru - Presidential candidates divided on gas deal renegotiation* (NRGI, 2016), resourcegovernance.org/sites/default/files/documents/peru-case-study.pdf.

37 Noting that some provisions might give rise to higher risks of arbitration, in particular as they might be considered as anti-competitive under EU or Japanese competition laws. See Steven P Finizio, "Destination Restrictions and Diversion Provisions in LNG Sale and Purchase Agreements."

38 Rushdi Maalouf, *International LNG Contracts*, OGEL, Vol. 16 - Issue 3, September 2018.

the competitive tenders could be organized by the upstream producer under government regulation.

- As the example of Trinidad and Tobago shows, governments should make sure offtake agreements do not conflict with relevant legal provisions and should enforce laws meant to ensure that actual realized sales prices concluded on an arm's length basis are used in calculating royalty and tax obligations. This includes empowering dedicated oversight bodies within the executive or the legislature.
- Alternatively, as the recent renegotiation with Shell in Trinidad and Tobago illustrates, governments and companies can agree on a benchmark price for all gas sold as LNG that better reflects market value. In this particular example, the benchmark price is the product of a formula that includes different market prices, transport and regasification costs. The use of a benchmark price limits the need for strict monitoring of LNG sales by the government regulator.
- Governments should request that investment agreements and other public concessions give government agencies or state-owned companies oversight authority and the right to audit contracts, destination of cargos, prices and costs. Offtakers should be required to provide all relevant information to regulators including sale contracts and cargos' tracking information.

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