



**INSTITUTE OF ENERGY
FOR SOUTH-EAST EUROPE**

Long-Term Gas Contracting

Terms, definitions, pricing
- Theory and practice

Gina Cohen

Lecturer & Consultant on Natural Gas

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An IENE Study (M55)

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I would like to start by thanking my mentor, John Astrop. John has been there for me since I started to work in the natural gas industry. He has taught me with patience and intelligence for the last two decades. I have learnt from his endless knowledge on how to negotiate and craft gas sales and purchasing contracts from personal experience witnessing him in the act, seeing him strategize to achieve the best outcome for his clients whilst he was constantly exalting the need for clarity, fairness and win-win situations for all parties involved where possible.

Gina Cohen
May 2019

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Contents

ACKNOWLEDGMENT	2
DISCLAIMER	2
Contents	3
LIST OF ABBREVIATIONS	5
1. INTRODUCTION	6
2. GAS MARKETS - BACKGROUND	7
3. GSPA FUNDAMENTALS	9
3.1 Definitions and functions	9
3.2 Purpose of long-term gas contracting	10
3.3 Duration of GSPAs	11
3.4 Emergence of long-term gas contracting	12
4. CONTRACT TERMS AND DEFINITIONS	15
4.1 General	15
4.2 Credit rating & guarantees	15
4.3 Warranties	16
4.4 Volumetric aspects	19
Contract quantities	19
Take or Pay	27
Make-Up Gas (MUG)	32
Carry-Forward Gas	41
Maximum/Excess Volumes	43
Downward Quantity Tolerance & Upward Quantity Tolerance	45
Shortfall Gas	48
Seller's Commercial Default	52
4.5 Gas nomination procedures – delivery program	53
4.6 Assignment	61
4.7 Liability	62
4.8 Conditions Precedent	63
4.9 Force Majeure	65
4.10 Political Risk	72
4.11 GSPA termination clauses	75

4.12 Tax stabilization clauses.....	85
4.13 Destination clauses	85
4.14 Most Favoured Nation clause (MFN).....	87
4.15 Additional points of negotiations.....	94
5. LNG CONTRACTING.....	96
6. GAS PRICING	102
6.1 Introduction.....	102
6.2 Price Negotiations in a GSPA.....	106
6.3 Elements of gas pricing	107
6.4 Gas price indexation.....	108
Oil indexation.....	111
Alternatives to oil price indexation	116
US LNG exports pricing formula.....	116
Inflation linkage.....	118
Gas-on-gas competition	119
6.5 Floors, ceilings and price stability	121
6.6 Price re-openers / Price reviews.....	122
6.7 Gas hub and hub pricing	125
What is a hub?.....	125
Secondary gas market.....	125
6.8 Future of gas pricing.....	130
7. CONTRACT EVOLUTION.....	131
8. SUMMARY	133
9. CONCLUSION.....	134

LIST OF ABBREVIATIONS

2PMFN - Two Party Most Favoured Nation	MAQ - Maximum Annual Quantity
3PMFN - Three Party Most Favoured Nation	MCC - Meeting Competition Clauses
ACQ - Annual Contract Quantity	MDQ - Maximum Daily Quantity
ADP - Annual Delivery Program	MFN - Most Favoured Nation
Bcf - Billion Cubic Feet	MHQ - Maximum Hourly Quantity
Bcm - Billion Cubic Meters	Mmcf - Million Cubic Feet per Day
CAPEX - Capital Expenditures	Mmscf - Million Standard Cubic Feet
CP - Conditions Precedent	MMBtus - Million British Thermal Units
CPI - Consumer Price Index	MUG - Make-Up Gas
DC - Delivery Capacity	NBP - National Balancing Point
DCQ - Daily Contract Quantity	NGA - Natural Gas Authority
DES - Delivered ex-Ship	NPV - Net Present Value
DQT - Downward Quantity Tolerance	OPEX - Operational Expenditures
FID - Final Investment Decision	P&P - Proven and Probable
FM - Force Majeure	PPA - Power Purchase Agreement
FOB - Free on Board	PUA - Public Utility Authority
GSPA - Gas Sales and Purchasing Agreements	ROFR - Right of First Refusal
HCQ - Hourly Contract Quantity	ROI - Return on Investment
IEC - Israel Electric Corporation	TCQ - Total Contract Quantity
INGL - Israel Natural Gas Lines	TOP - Take or Pay
IOC - Independent Oil Company; International Oil Company	Tpy - Tons per year
IPPs - Independent Power Producers	TTF - Title Transfer Facility
JCC - Japan Crude Cocktail	UQT - Upward Quantity Tolerance
LNG - Liquefied Natural Gas	

1. INTRODUCTION

The last several years have been marked by considerable discourse between the natural gas market participants, regulators, and other stakeholders about the legal frameworks of international and local gas trade. While there have been a number of papers on the subject, including on the differences between spot, short term or long term contracting, as well as on gas pricing, I will try to focus more in this paper on the main characteristics of long-term gas contracts. A lot will be based on my personal experience, and so the paper will neither be all-encompassing nor a purely academic theory purporting to describe a perfect world, but rather based on the understanding that on many aspects there are few general rules and that a lot is down to negotiations.

This paper deals with the Gas Sales and Purchasing Agreements (GSPAs¹), which serve as a tool for the division of market risks by means of tying natural gas Sellers and Buyers for a considerable period. Because of the highly capital intensiveness and market orientation of gas development, Gas Sales Agreements have been one of the fundamental tools enabling Sellers to invest in exploration, production and development of gas fields, transporters to promote essential gas transportation infrastructure whether pipelines or liquefaction facilities, and Buyers to invest in consumer facilities, secure in the knowledge that they will have the gas supplies needed for their project's life-span.

Although the market is now moving towards shorter-term contracts, extensive reliance on short-term and spot transactions in greenfield markets would not have enabled the parties to obtain the financing needed to develop their market. Even today, the international LNG market still has a dominance of long term contracting, although here too, short-term and spot contracting is experiencing growth. Thus, in 2000, only 5% of the world's LNG was sold on a spot basis or on short-term contracts, by 2017, that was up to 27% (IGU & IHS).

The aim of this paper is to empirically analyse and draft an overview on gas sales and purchasing contracts. The intention is not to consider all the gas contracting issues, rather only the GSPA fundamentals, such as the main terms and definitions, issues of firm volume and flexibility, and some of the gas pricing issues. The text is supplied with actual examples and case studies and various aspects of GSPA practical application, including disputes, case questions and studies. The research provides both factual data and practical recommendations for both parties of the contract.

¹ Or Gas Sales Agreements (GSAs).

Certain related references are made to gas contracts in Israel, as this is where the author is based, and the topic is interesting due to the recent significant discoveries of natural gas offshore Israel as well as in other countries in the Eastern Mediterranean. Israel is currently facing challenges of expanding its gas delivery infrastructure to adequately accommodate growing domestic natural gas demand and potential regional and international exports to Europe. These challenges are frequent in greenfield gas markets and are just as relevant to the other countries in the Eastern Med, characterized by undeveloped gas market regulations and legislation systems, and where long-term contracting may be a requisite for achieving the objectives and thus can be adapted as an ideal learning tool. Europe is keeping a keen eye on all these developments, as the potential market for absorbing some of the surplus gas that will hopefully be exported from Israel, Palestine, Cyprus and Egypt.

The paper is intended to be a practical tool for both students and individuals involved in GSPA negotiations and drafting.

2. GAS MARKETS - BACKGROUND

Gas markets in various regions regularly undergo changes, which can be divided in the following stages of evolution: greenfield, brownfield and mature.

In the beginning, when they are greenfield markets with only 1-2 producing gas fields, limited infrastructure and half a dozen Buyers, they develop mostly as monopoly markets, and require long-term contracts to be signed between the gas Seller and Buyer, with the price usually indexed to the price of oil. As the markets mature towards brownfield markets with the emergence of competition and the breaking-up of monopolies, and/or have evolved into such because of changes of circumstances (e.g. import regasification terminals in the US, which are converted to export liquefaction facilities), term contracts are still required but there is the start of gas-on-gas competition.

In more mature markets, with dozens of fields and hundreds of Buyers, with a fully competitive gas and electricity market and unlimited infrastructure with 3rd party access, with increasing market deregulation, both Buyers and Sellers have a much higher degree of certainty that they can sell and buy gas into a spot or hub market. In mature markets, spot gas and electricity are traded on anything from an hourly basis, to daily, weekly, monthly and annual basis. At this stage, the developers of gas fields no longer see the need to have long-term dedicated gas contracts because they are confident that they can sell all their output for whatever period

they want at the prevailing 'spot' price. There may still be long-term GSPAs in place, but the price is simply linked to daily/monthly spot prices in the market. Depending on the terms in the contract it may be at a premium or a discount to the 'spot' price for the period in question.

This is a process which historically takes decades to evolve. Even today, over 65% of gas flowing into Europe is done under long-term contracts, even if the price mechanism has changed considerably. In Israel, the market is still characterized as a greenfield market with only one producing gas field (Tamar and some spot LNG imports) and one prominent gas Buyer (Israel Electric Corporation), responsible for 90% of the consumption in the market when the field was developed (IEC's share is falling with each year since 2013 as the electricity monopoly supplier is being broken-up).

Because natural gas is in a gaseous state rather than a liquid state as is oil, it is harder to transport and store. This has a number of implications. The first is that about 70% of gas in the world is traded locally (compared to 70% of oil traded internationally), leading to local supply and demand fundamentals and pricing rather than global. Total gas consumption in 2017 was 3,680 bcm out of which 1,134 bcm was internationally traded (740.7 bcm by pipeline and 393.4 bcm by LNG), so that only 10.7% of gas consumed worldwide is traded as LNG².

The second implication of the gaseous state of natural gas (contrary to oil in most cases) is that it requires complex and expensive upfront infrastructure investment to be made to transport it (pipelines, LNG facilities) and to consume it (e.g. power stations). The investment across the chain amounts to billions of dollars and so Sellers and Buyers alike (and the financing institutions at both ends) need to know, with a high degree of certainty, that the gas will be available for many years (15-20 years) and that the terms (price, volume) of the sale/purchase are generally known in advance by all parties. This is especially so in new and immature markets, and if the players need a high degree of financing.

On many occasions, a gas field is developed specifically for a power project(s), dedicated to a certain market, and unless the market is a very liquid one (such as mainly exists in Western Europe and North America) gas fields are in fact usually not developed unless an anchor Buyer has purchased sufficient volumes of gas for the long-term at a high enough price to justify the cost of developing the field. As a gas consumer, the power station is just as dependent on the certainty that it

² BP Statistical Review of World Energy 2018 - <https://www.bp.com/content/dam/bp/en/corporate/pdf/energy-economics/statistical-review-2018/bp-statistical-review-of-world-energy-2018-full-report.pdf>

will have gas to generate electricity to sell to the clients with whom it has signed long-term power purchase agreements (PPAs) if it is an independent power producer or to the market in general if it is a utility essential service provider.

What is happening though currently with such huge uncertainties regarding oil and gas pricing is that Buyers are remaining on the fence and are more reluctant to sign new long-term contracts, especially whilst spot or hub prices are often cheaper than contract prices and whilst portfolio players are developing, which in turn makes it harder for new complex upstream or LNG projects to get financing and develop.

With more open markets, new additional instruments develop, such as selling into a liquid market, as well as more flexible LNG deals, and a new phenomenon known as portfolio players or aggregators starts to develop. Nevertheless, long-term gas contracts will probably remain an important instrument throughout the world, although with increasing flexibility on a number of fronts, including hub-based prices, the lessening or even riddance of destination clauses as markets mature and as more LNG comes on line and is consumed.

3. GSPA FUNDAMENTALS

3.1 Definitions and functions

A Gas Sale and Purchase Agreement (GSPA) is a long-term contract reached in bilateral negotiations for the sale and purchase of natural gas between a willing Seller and a willing Buyer. It is a contract that is meant to mitigate the risks, cope with long-term issues and changes which may occur throughout the life-span of the contract, maintain a balanced tension between Buyers and Sellers and give the Buyers and the Sellers what each side needs most, depending on their relevant profiles and characteristics.

There is a way that gas contracts are crafted and have been crafted historically.

The process of negotiating and signing a GSPA usually passes stages that include some or all of the following: marketing, signing a memorandum of understanding (MoU), signing a Letter of Intent (LoI), signing Heads of Agreement (HoA), signing the final GSPA/GSA.

The risks in development of gas fields are quite large and so the developers need certainty up-front. When the gas developers start-off on the journey there are huge

risks, which include reservoir reserves, extra costs that could be incurred down the line, or uncertainties on a host of levels (geopolitical, regulatory, market, competition) and thus field producers need safe launch anchor customers to agree to take some seemingly fairly onerous terms, commit to large enough volumes and high enough prices to get financing and ensure field development.

Economically, long term GSPAs are identified as serving the following functions³:

- To allocate price and volume risk between the parties to the contract;
- To reduce transaction and switching costs;
- To create long-term relationships between parties that can result in synergies without vertical consolidation.

A GSPA is a bundled product of commitment and flexibility, which if well-crafted is due to maintain a balanced tension between Buyers and Sellers throughout the lifespan of the contract. The specific terms can vary widely from contract to contract and at the end of the day each term is open to negotiations. Each contract is negotiated based on the parties' particular needs, their relative bargaining power, and the circumstances surrounding their contractual relationship and the relevant market.

Long-term GSPAs are useful instruments to create a stable balance between gas Sellers and Buyers. The success of a GSPA depends to a large extent on the parties' ability to match appropriate contractual terms with the specific circumstances of the Seller's upstream development and the Buyer's downstream consumption.

In any study that delves to understand GSPAs, it is necessary to understand both how they function when the signatories are parties in the same country (thus the gas is earmarked for the local market) as well as some of the intricacies if these are interstate contracts, between a Buyer from one country and a Seller in another.

3.2 Purpose of long-term gas contracting

The main issue of the long-term contracts is that they act as a critical factor for investment in timely infrastructure projects, as they are important for managing risks and provide guarantees to all participants. The gas markets have high entry barriers, and limited physical mechanisms from which they can source other

³ <http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/Henning%20Long-Term%20Contracting.pdf>

supplies. Only in a very liquid market with dozens of suppliers, the market can manage with mostly spot and/or short-term contracts.

The main purpose of GSPAs is bringing the gas producer and the gas purchaser into an exclusive relationship with clearly defined rights and obligations arising from the significant upfront capital investment involved in gas fields and other long-term infrastructure needed to bring the gas from the delivery points to the purchaser's consumption facility.

These contracts provide the environment, which maintains the gas producer and purchaser's intentions by means of offering the gas producer guarantees of minimum cash flow, and the purchaser with constant and regular, albeit flexible supplies of gas.

Long-term contracts have been utilized for many years to deal with the long-term nature and high specificity of investments in all parts of the gas chain from exploration and production to the final consumer, such that production is linked to the final consumer in a way that allows the participants to hedge their long-term risks of gas supply and earn an adequate return on investment (ROI).

The obligations between the gas producer and the purchaser are diametrically opposed to each other to the extent that regardless of fluctuations in demand, the gas producer must necessarily rake in some minimum revenue, while the gas purchaser takes the sole responsibility of the contract because whether it takes the minimum quantity or not, it must pay for the gas.

3.3 Duration of GSPAs

Long-term GSPAs have evolved substantially over the decades and are often long-term contracts, with contractual terms ranging between 20 and 30 years. The whole point of long-term contracting is to provide as many safe and reliable conditions as possible, to enable the development of new gas fields.,

The recent trend has shifted the GSPAs to shorter terms, with 10 to 15 years⁴ or even shorter terms for both pipeline and LNG sales⁵ becoming more common.

However, in a non-liquid market and depending on circumstances and the character of the Buyer, in an ideal world, a Buyer would want to do a deal for 30

⁴ Luca Franza, 'Long-Term Gas Import Contracts in Europe: The Evolution in Pricing Mechanisms', CIEP Paper (2014), at p. 18.

⁵ Steven P Finizio, 'Destination Restrictions and Diversion Provisions in LNG Sale and Purchase Agreement', in J William Rowley QC (ed.), *Global Arbitration Review: The Guide to Energy Arbitrations*, (2015), at p. 182.

years and not have to do any other deal throughout the life span of its facility. This is especially true if the Buyer is a new power station which needs financing and PPAs to get established. Thus, the highest flexibility that the Buyer can build into its contract (namely the lowest TOP) is what Buyers seek in terms of term/volume flexibility, at the lowest price possible. This gives them the guarantees they need that they will have gas with the maximum flexibility to offtake various volumes from possibly different sources as the market develops. In any case, usually new Buyers cannot have a short-term contract due to bank financing obligations. That brings them to a requirement to enter at least into a 15-year contract.

If a Buyer is a medium-small size industrial plant, it will want maximum flexibility, and Sellers should even consider allowing such a Buyer to buy gas with no Take or Pay (TOP) obligations, just based on “best endeavours”. This is something that Israel, which is a greenfield market and where industrial demand for gas is small, has failed to grasp and is one of the hurdles that has slowed-down the sale of gas to this sector. Only in 2019, has Israel decided to take a preliminary look at how to develop a spot and secondary gas market.

Even in Europe, it is only on the periphery of sales’ opportunities that there is a spot market. The LNG market is also still underpinned effectively by the 70% of LNG which is still traded on a contract basis and because the Sellers and the Buyers are often more than 5,000 km apart, which requires an array of complex and expensive transport costs to sanction new projects.

3.4 Emergence of long-term gas contracting

For decades, natural gas trade in many parts of the world has been characterized by strong bilateral ties between the Buyers and the Sellers, underpinned by binding contractual arrangements that lock them into a long-term relationship. These ties and arrangements evolved as a result of the fears of those who built highly capital-intensive pipelines that the Buyers might behave opportunistically once a pipeline had been completed. To mitigate such risk, the Sellers insisted on contracts that were long-term and included Take or Pay (TOP) clauses.

Ironically, Buyers also had a strong hand in enabling the development of long-term contracts with TOP clauses. In the early 1960s, air pollution in Japan led to the enactment of environmental regulations, which stirred Japan's interest in importing LNG as a cleaner and more environmentally friendly fuel for power generation than coal and crude oil.

On 6 March 1967, the first Asian LNG sale and purchase agreement was signed for the sale of LNG from Alaska to Tokyo, with the first delivery of Alaskan LNG to

Tokyo Electric and Tokyo Gas occurring in November 1969⁶. Within a few years, Japanese Buyers were providing a market for Brunei and then Indonesia LNG. Although the price element was an important aspect, the Japanese Buyers were more focused on guaranteeing a steady, safe supply and were less concerned about price volatility. In fact, the Japanese government was keen on helping to facilitate the construction of export LNG projects and even gave loans to the Indonesian government and to Pertamina⁷. In addition, major credit-worthy Japanese Buyers were willing to guarantee the purchase of volumes of gas, explicitly to ensure that investors and banks had the requisite comfort to invest in high-risk, capital-intensive LNG export projects.

Early LNG developments in the 1970s were driven by oil companies that had the misfortune to discover natural gas distant from gas markets. The discovery would have been stranded but for the advent of integrated LNG developments to liquefy, transport and regasify the gas for use in power plants and local distribution. Although LNG was more expensive than oil, utilities in Japan and Europe were prepared to sign long-term, take-or-pay contracts because of natural gas' low emissions and enhanced energy security through the interdependence of buyer and seller and diversification from oil⁸.

The price was determined based on the replacement value of the gas, which in practice meant the price of oil, as the main competing fuel. Destination clauses, restricting the right to re-sell gas, prevented the Buyers from seeking arbitrage opportunities and enabled price discrimination. Much of this was introduced in the early 1960s, to underpin the development of the super-giant Groningen gas field in the Netherlands. Later, these elements formed the basis for Soviet/Russian gas exports to Europe.

With the rise of LNG trade, many of the elements that characterized pipeline-based trade were adopted for LNG, despite the inherently different nature of the trade relationship. Oil indexation, Take or Pay contracts and destination clauses became common features of LNG trade in the Asia Pacific region as well as between North Africa and Europe. As the first wave of Asian long-term contracts for LNG expired in the 1990s, the Buyers started pushing for more flexibility such as lower TOP, shorter term contracts and a weakening of the oil-price linkage (the implementation

⁶ <https://www.lexology.com/library/detail.aspx?g=1d775cb2-c99f-4019-b142-214731b8e828>

⁷ Indonesian state-owned oil and natural gas corporation based in Jakarta. It was created in August 1968 by the merger of Pertamina and Permina.

⁸ <https://naturalgasworld.cmail20.com/t/d-l-bhukyit-yhkklytia-q/>

of the S-curve into the pricing formula reduced price volatility⁹). But most LNG trade remained on a point-to-point basis from a specific Seller to a specific Buyer.

The emergence of the US as a likely LNG importer in the mid-2000s presented a big potential market opportunity. The US gas market was already highly liquid and underpinned by spot trade, so potential US gas importers were not willing to enter restrictive long-term contracts based on an oil-indexation price. Moreover, the rise of gas use in the power sector exposed gas to competition from coal, putting the use of oil linkage further into question. With Qatar starting to develop one of the world's lowest cost reserves of natural gas (North Field), the consortia developing the LNG projects were willing to accept larger-than-usual portion of market risk closely in line with the growing role of spot LNG trade, from potential Buyers in the US and the UK.

This all took on a totally different proportion when the shale gas revolution took off in the late 2000s in the US, having marked repercussions on international LNG trade, even before a single cargo was exported from the US in February 2016. Rapid growth of shale gas output meant that the US would not need the large-scale LNG imports that had been anticipated. Consequently, uncontracted LNG from Qatar and other sources that had been slated for the US, needed to find a new home.

In Europe, this period coincided with important gas market reforms aimed at improving market integration, transparency and third-party access, developing bi-directional pipeline flows and increase use of hub pricing. This was exasperated, from 2010 with a slow-down in natural gas demand in Europe (gas demand in Europe has in the meantime recuperated reaching 491 bcm for 2017, being the highest consumption since 2010 when consumption was 527 bcm¹⁰).

With this, the conditions were available for arbitrage between readily available cheap gas on the spot market and more costly supplies priced under existing oil-linked long-term contracts.

The combination of regulatory changes and a market awash with gas, ultimately triggered a process of renegotiations of contract terms with the main pipeline exporters, and concessions such as from Gazprom started.

⁹ An S-curve formula is where the price formula is different above and below a certain oil price, to dampen the impact of high oil prices on the Buyer, and low oil prices on the Seller. The formula would include a floor and a cap price to safeguard developers/Sellers on the low end and Buyers on the high end.

¹⁰ EU Commission, Quarterly report on European gas markets; Vol. 10, arch 2018

4. CONTRACT TERMS AND DEFINITIONS

Below are detailed some of the contract terms and explained some general issues. Some of the paragraphs contain case studies and/or some practical recommendations.

4.1 General

In the initial part of the contract, the parties are named, and definitions are provided for the important terms. Some of the main points to be checked and settled in these parts of the GSPA are the following:

- Need to check that all the definitions are provided.
- Need to check that none of the definitions clash and/or overlap (e.g. 'Political Interruption Events' vs. 'Political Risk Events').
- Need to ensure that the definitions are identical for the Buyer and the Seller.
- Need to understand why one particular term is used in the GSPA rather than another.
- Under definition of facilities – ensure that the facilities are indeed fully owned by the signatories of the GSPA and that there is no clash.

4.2 Credit rating & guarantees

The credit rating of each party is essential for the counterparties to understand their credit cover, which protects their accounts receivables from loss due to credit risks such as protracted default, insolvency or bankruptcy of the other party. Credit cover can normally be provided by different forms of guarantees, such as a corporate guarantee, issued by another gas supply company, a bank guarantee or a Letter of Credit, issued by one of the top banks rated by top credit rating agencies¹¹ or a guarantee, issued by a credit insurance provider.

Case: Is there a need for complete reciprocity in credit rating guarantees to be provided by the Buyer and the Seller?

¹¹ <https://www.sec.gov/Archives/edgar/data/72207/000119312512337867/d384852dex101.htm>

In a GSPA, it is mostly incumbent upon the **Buyer** to provide a suitable form and level of guarantee and credit rating, as the Buyer has the main obligation to pay under the contract.

Complete reciprocity, however, is not required from the **Seller** in terms of credit rating and guarantees since the level of payments a Seller is exposed to is much lower than a Buyer. However, some form of support/guarantees are required to be provided for the Seller to cover obligations for events of major Shortfall payments and termination events.

4.3 Warranties

Warranties are the part of the contract where each party makes certain warranties to the other and is quite self-explanatory, based on the examples provided below. Warranties can, of course, be suited to the explicit circumstances required.

Case: Example of wording for Sellers' warranties

Warranties of the Sellers – Without prejudice to any obligation of the Sellers under the agreement, each of the Sellers (as to its Seller's Percentage) warrants to the Buyers as of the Effective Date of the agreement, as follows:

- (a) Warrants that title to all gas sold and delivered by such Seller under the agreement and that all gas delivered by such Seller shall, upon delivery, be free from all liens, charges, encumbrances and adverse interests of any and every kind;
- (b) warrants that the Sellers' Petroleum Rights are valid and subsisting and are free from all liens, charges, encumbrances and adverse interests of any and every kind, other than the charges listed in clause [xxx];
- (c) under the Sellers' Petroleum Rights, the Sellers have discovered accumulations of natural gas currently estimated to be in excess of [xxx bcm] (Proved and Probable Reserves) within the reservoir and have, subject to receiving all permits required under law, the right to produce, sell and deliver natural gas from the reservoir in accordance with the terms of the agreement for the whole of the Contract Period;
- (d) the Sellers have no knowledge of any matter which might prevent it from producing natural gas from the reservoir or from transporting, processing, delivering and selling specification gas to the Buyer at the delivery point

through the Sellers' Facilities in accordance with the terms of this Agreement for the duration of the Contract Period;

- (e) warrants that it is a corporation duly established and validly existing under the applicable laws of its respective jurisdiction of incorporation; or... it is duly organized and validly existing under the laws of the jurisdiction of its formation and it has the legal right, power and authority to conduct its business and execute and deliver the agreement and observe and perform its obligations under the agreement;
- (f) warrants that it has the power and authority to execute, deliver and perform the agreement and that such execution, delivery and performance have been duly authorised and approved by the board of directors or other competent organ of such Seller;
- (g) warrants that no other corporate or governmental proceedings on the part of such party are necessary to authorise and approve the signature of the agreement; or the entry by it into and performance of the agreement is within its power and has been duly authorized by all necessary action on its part and shall not breach any law or determination or provision applicable to its governing documents;
- (h) warrants that it has authorised its designated representative to execute on its behalf the agreement and, once executed, the agreement shall be binding and fully enforceable against it;
- (i) the Seller and any director, officer, employee or affiliated company of such Seller has not made, offered, or authorized and will not make, offer, or authorize with respect to the matters which are the subject of the agreement, any payment, gift, promise or other advantage, whether directly or through any other person or entity, to or for the use or benefit of any public official (i.e., any person holding a legislative, administrative or judicial office, including any person employed by or acting on behalf of a public agency, a public enterprise or a public international organization) or any political party or political party official or candidate for office, where such payment, gift, promise or advantage would violate the applicable laws of [Seller's Country] or [Buyers' Country]... [and as per relevance].

Case: Example of wording for Buyers' Warranties

Warranties of the Buyer - The Buyer warrants to the Sellers as of the Effective Date of the agreement as follows:

- (a) warrants that it is a corporation duly established and validly existing under the laws of its jurisdiction of incorporation [Country];
- (b) warrants that it has the power and authority to execute, deliver and perform the agreement and that such execution, delivery and performance have been duly authorised and approved by the board of directors or other competent organ of the Buyer;
- (c) warrants that no other corporate or governmental proceedings on the part of the Buyer are necessary to authorise and approve the signature of the agreement; and
- (d) warrants that it has authorised its designated representative to execute on its behalf the agreement and, once executed, the agreement shall be binding and fully enforceable against it;
- (e) the Buyer and any director, officer, or employee of the Buyer or any affiliated company has not made, offered, or authorized and will not make, offer, or authorize with respect to the matters which are the subject of the agreement, any payment, gift, promise or other advantage, whether directly or through any other person or entity, to or for the use or benefit of any public official (i.e., any person holding a legislative, administrative or judicial office, including any person employed by or acting on behalf of a public agency, a public enterprise or a public international organization) or any political party or political party official or candidate for office, where such payment, gift, promise or advantage would violate... (as per relevance).

Mutual Warranties

The Buyer and Sellers further warrant that the execution and delivery by them of the agreement does not and (on the basis of their knowledge and belief at the date of the agreement and subject to the satisfaction of the Conditions Precedent) their performance of the agreement will not:

- a. contravene any provisions of their constituent documents;
- b. whether or not after notice or lapse of time or both, conflict with, result in a breach of any provision of, constitute a default under, result in the modification or cancellation of, or give rise to any right of termination or acceleration in respect to any agreement, instrument, indenture, contract, lease, concession, obligation or other commitment to which it is a party or by which it may be bound or affected, or require any consent or waiver of any party to any of the foregoing;
- c. violate or conflict with any applicable law or other requirement of any governmental, administrative or judicial authority or arbitral tribunal applicable to it;
- d. require in respect of such party any authorisation, consent, order, permit or approval of, or notice to, or filing, registration or qualification with, any governmental authority, other than such consent as has been obtained prior to the date of the agreement and is in full force and effect or is periodically obtained in the ordinary course of business;
- e. all negotiations relating to the agreement and the transactions contemplated hereby have been carried on without the intervention of any person acting on their behalf in such manner as to give rise to a valid claim against any of the other Parties for any broker's or finder's fee or similar compensation in connection with the transactions contemplated by the agreement; and neither they nor their employees nor any of their affiliates or their employees has offered, promised or given any undue pecuniary or other advantage, whether directly or through intermediaries, to a government official or to a Third Party to ensure that the official or Third-Party acts or refrains from acting in relation to the performance of official duties in order to obtain any improper advantage in connection with the transactions contemplated under the agreement.

4.4 Volumetric aspects

Contract quantities

Normally, GSPAs include a host of volumes and quantities that represent the Buyer's requirements and the Seller's availability to supply (in terms of the volume it holds and the infrastructure it has/will put in place).

The terms relating to the volumes in GSPAs include first and foremost some stringent long-term volume sales and purchase requirements which the Buyer has to commit to.

These volumes include Total Contract Quantity (TCQ) and Annual Contract Quantity (ACQ) which are directly related. They include Daily Contract Quantity (DCQ), Hourly Contract Quantity (HCQ), Delivery Capacity, Downward Quantity Tolerance (DQT), Minimum Nominations and Seller's Obligation to Deliver.

Some of these main terms and definitions are introduced below:

Total Contract Quantity (TCQ) - This is the total contract quantity over the full life span of the contract. When the Buyer has taken his TCQ, his contract terminates. The Buyer cannot take more than his TCQ. The TCQ may be reached at the agreed termination date for the contract, or it may be reached earlier and/or later, depending on circumstances. The volume is often expressed in trillion BTUs.

Annual Contract Quantity (ACQ) - This is the quantity of gas in MMBtus that is equal to the sum of all the DCQs for the year. It can be expressed as a distinct number or as a multiple of DCQs. It is the volume of gas which the Seller must deliver, and the Buyer must take in any given contract year.

A GSPA may have one ACQ that applies to every year of the contract, or it can have different ACQs for different years. For example, if a Buyer's electricity sales' market is growing, it might seek to escalate its ACQ over time, maybe together with the construction of a phased approach to further facility construction over time. On the other hand, if the market in which the Buyer operates is opening up to competition it may wish to have the ability to reduce its ACQ. In practice, many contracts are written in forms which allow the Buyer to take considerably below the stated ACQ.

Annual Delivery Program (ADP) - A long-term schedule commonly used in the liquefied natural gas (LNG) industry for optimising inventory and delivery planning (may also be referred to as the annual operating plan).

Daily Contract Quantity (DCQ) – This is the quantity of gas in MMBtu for each day. In most GSPAs, this is in accordance with the maximum operational daily needs of the consumer. In some GSPAs, it is calculated based on the annual contract quantity divided by 365.

Plateau DCQ and Decline DCQ - In a depletion contract, the GSPA will define the Plateau DCQ, which can be for a fixed period or for a fixed proportion of the reserves. After the end of the plateau DCQ, a depletion contract will enter the Decline Period, during which the DCQ will be reset each year according to the remaining production capacity of the gas field in question.

Hourly Contract Quantity (HCQ or Maximum Hourly Quantity - MHQ) – This is mostly important and used for operational purposes of the whole supply gas system to all consumers during peak demand hours, or when the system has/is in limited supply capacity and distribution considerations are done on an hourly rather than daily basis.

Delivery Capacity (DC) - This is the contract quantity that the Buyer is designated to buy, and the Seller is supposed to deliver. It is generally set as a fixed percentage of DCQ, which is known as **Swing** and defined as a ratio of peak volume sold to average volume sold expressed as a percentage. Thus, the Seller is obliged to supply DCQ plus Swing (i.e. Delivery Capacity) which is termed as Seller's obligation. However, Buyer can request to take up to DCQ minus Swing. The swing remains constant throughout the life of the contract; a seasonal variation, however, can be incorporated in the contract.

Contract years

Many of the concepts above and below refer to annual volumes of gas.

When discussing a Contract Year in a GSPA, this usually refers to the calendar year, namely from 1st January to 31st December. Some GSPAs also include a Rolling Year, which is twelve months starting at any particular time.

It is important to have a definition of 'Rolling Year' if this term is used. A Rolling Year can be measured in a number of different ways, e.g. from a quarterly, monthly, weekly or daily point, looking back to the same point in the previous year.

It is confusing to use both Rolling Years and Contract Years in a GSPA, when calculating Take or Pay and Make-Up Gas and therefore it is best to stick to Contract Years, as mixing the two causes unnecessary difficulties.

Adjusted Annual Contract Quantity (Adjusted ACQ)

As stated, some GSPAs have different ACQs and different Minimum Bill Quantities at different periods throughout the term of the contract.

A good example is the case of Israel Electric Corporation in Israel, which until 2013, was the monopoly, if not sole power generator, in the Israeli market, which gradually saw its market share decrease to 71% by 2018. Thus, when signing its gas contract with the owners of the Tamar gas field in 2012, the electricity corporation was aware of its need to contract for adjusted volumes of ACQ over the term of the contract.

Case: IEC Adjusted ACQ and Minimum Bill Quantity

For each Contract Year during the Take or Pay Period (or that part of the first Contract Year commencing on the first Day of the Take or Pay Period and ending at the end of such Contract Year), the "Adjusted Annual Contract Quantity" and the "Minimum Bill Quantity" shall be calculated in accordance with the following provisions.

The Adjusted Annual Contract Quantity (or "Adjusted ACQ") shall be a quantity of Specification Gas equal to the ACQ applicable for the relevant Contract Year less the sum of the following:

- A. the aggregate of the quantities of Specification Gas Properly Nominated by the Buyer for delivery during the relevant Contract Year, which the Sellers did not for any reason deliver (including without limitation the Sellers' failure to deliver as a result of Force Majeure) but excluding any quantities that the Sellers failed to deliver in the circumstances of Article [*x] and any failure by the Buyer to take delivery of Specification Gas properly tendered for delivery in accordance with this Agreement; and
- B. The aggregate of the quantities of Specification Gas Properly Nominated by the Buyer for delivery during the relevant Contract Year which the Buyer did not take for reasons for which it was excused from liability under Article [Force Majeure Article] or as a result of the Buyer's exercise of any right to refuse to take delivery under Article [*x] and Article [Quality Article].

Article *x states that: In the event of failure to pay any sum due pursuant to this Agreement which is not the subject of a dispute under Article [***] for seven days from the applicable due date, then the Party to whom the same is due and owing may on fourteen days prior notice to the other Party of the intention so to do, suspend delivery or receipt, as the case may be, of Specification Gas hereunder, and if such failure to pay continues for one hundred and twenty (120) days from the applicable due date, the Party to whom the same is due and owing may also, on fourteen days prior notice to the other Party, terminate this Agreement, but

the exercise of such right shall not constitute a waiver of, nor in any way prejudice, other remedies available to such Party.

The "Minimum Bill Quantity" or "MBQ" shall be a quantity of Gas equal to (**) of the Adjusted ACQ for each such Contract Year.

DCQ & HCQ

Parameters for DCQ can differ depending on the type of the Buyer's needs. If for example, the Buyer is an LNG liquefaction facility, it would be both content and required to take its DCQ at a uniform hourly rate during the course of the day.

If the Buyer is a power generation company, it will, however, ask for and will probably receive a "swing", which would provide additional intra-day flexibility and will be given an HCQ, which can differ considerably throughout the day dependent on peak, shoulder and low electricity generation times in said market. This is a benefit that is provided to the Buyer and is an additional burden on the Seller which has to be able to increase the flow of its wells and its whole infrastructure to meet the additional flexibility needs of the power plants. Gas demand at a power station can often ramp up or down by as much as 50% in any day. In such cases, the DCQ is 24 * the HCQ.

The process is often quite complex if the Buyer's gas demand profile varies considerably from one season to another. In such a case, the gas Seller may be required to build excess production, processing and transportation capacity that is only used during restricted times of the year. The incorporation of such excess capacity can result in higher gas prices.

Some Sellers, such as reflected in many of Gazprom's export contracts do not allow intra-day nominations, which in turn does not allow gas shippers to adjust inflows in case demand forecast changes. This is one reason for example, why Greece is currently expanding its LNG import capacity in order to improve the flexibility of the Greek market. The expansion of the Revithoussa LNG facility, Greece's only regasification plant, should facilitate balancing the system by limiting the country's reliance on Russian gas imports. Its LNG imports should be able to cover unexpected gas shortages, making it easier for Greece to keep its grid in balance.

However, generally speaking, markets have a variety of external and internal options to help minimize the need for having to construct excess capacity. An ideal

way to deal with such a situation is to identify a counter-swing customer, namely one that needs gas in an inverse fashion to the first customer (e.g. under-utilized winter gas capacity in hot countries could be sold as LNG, or industrial facilities that use more expensive fuels and can switch fuels when cheaper natural gas is available on an interruptible basis). Swing can also be well managed by storage. With storage, the same volume of gas is provided throughout the year and the non-consumed volumes are injected into storage by the Buyer, which it can consume during peak demand time or in case of a cut-off.

As stated, although building in extra capacity for peak demand is reflected in higher costs (to the Seller) and thus a higher gas price (for the Buyer), which the Buyer may be willing to pay, it is not always automatically in the long-term best interest of the Seller to increase the price for this service. The Seller wants its client to be able to meet its costs over the long term in a stable manner and wants the gas it sells to be competitive against alternative fuels and/or alternative gas suppliers. Sellers will therefore strive to ensure that the GSPA meets the Buyer's demand profile as narrowly as possible so as not to impose unnecessary surplus costs. The difference between a narrowly tailored gas price and one inflated due to excess capacity could affect a country's/Buyer's growth consumption rate or its ability to compete with other countries/Buyers or simply make the contract terms more vulnerable to normal economic cycles.

Case: Importance of MHQ where there is only one gas supplier in a market

In Israel, as of the writing of this document, the Tamar gas field is the main (97%) supplier of all the gas to the market with some small supplies of LNG supplied during peak demand or emergency times. Thus, the Tamar field determines the gas pressure in the Israel Natural Gas Lines transmission system (INGL), the amount of linepack in the system, and the hourly flexibility for all operational needs to enable the regular supply of gas to all consumers including during peak demand hours.

Until another gas field is connected to the Israeli coast (Leviathan is anticipated to be connected in November 2019 and Karish in 2021) and thus to the national high-pressure transmission system, the whole system in Israel is at the limit of its supply capacity. During some of the time, the hourly demand in the market amounts to the maximum hourly supply capacity from Tamar. There are a few hours a year when the hourly demand is greater than the maximum hourly supply capacity of the field (at such times the line pack in the INGL system and/or the imported LNG is used). Under such conditions, each consumer's hourly needs are important. This problem will mostly be solved once another field Leviathan has been

connected. All agreements in Israel with suppliers and INGL are based on daily and not hourly supplies.

Normally, the Seller is obliged to provide the ACQ within each year throughout the term of the contract; the Buyer is obliged to take the gas according to the Take or Pay terms and conditions (see definition below). The Seller must legally do its best endeavours to provide the Max DCQ/ACQ but, depending on what is agreed in the GSPA, is not usually obliged to do so.

Gas reserves

A gas field has finite volumes of hydrocarbons which cannot be replenished and so in those instances where the GSPA is based on what is known as a Depletion Contract¹², rather than a Supply Contract¹³, it is even more imperative that the volumetric clauses be rather restricted¹⁴.

The Seller can only sell based on its reserves, and on the production capacity of its facilities. The Seller must have the reserves to cover the remaining ACQs that it has contracted for, failing which it will be in default of its contract and will have to pay the fines imposed. Reserves however are also dynamic, and the Seller gets a better view of what the final reserves will be the more advanced into production it moves. The final reserves' figure is only fully known when the last drop of gas has been produced from a field. Overselling reserves can lead Seller into default, again depending on the type of contract. If the contract is a depletion contract, then the Buyer also takes reserves' risk.

In addition, the Buyer's concerns about the Seller overselling from a field, is also contingent on what alternative sources of gas supply are and/or may become available in the future to the Buyer, and the likely price of such alternative resources. If the Buyer is in a stronger position than the Seller, then the Buyer may be able to insert a clause in the GSPA stating that "the Seller could be required not to sell more than [50% under extreme circumstances] [80% under more reasonable circumstances] of its Proven and Probable reserves (P&P) for the first 3 years of supply and not to sell more than 100% of its P&P after that".

¹² Depletion contract is a type of contract in which the sale volumes are governed by the performance characteristics of the particular gas field.

¹³ Supply contract is a contract in which the Seller undertakes to supply gas in guaranteed volumes over a fixed period of time envisaged in the contract, having a right and/or an obligation to substitute other suitable gas if necessary.

¹⁴ Gazprom for example does not link new supply deals to any particular fields, under the principle that gas must first be sold and only then it is produced and pipeline.

However, the limitations placed on Sellers in terms of how much gas they can contract to sell (both at the outset of GSPA negotiations and a few years later on) should not be unduly limiting. At the end of the day, each party's room to manoeuvre depends on the relative strengths of Buyers and Sellers during the negotiations as well as the proportion of the field being sold in any individual GSPA contract, as well as the terms of the contract.

The Buyer should accept having no rights to receive detailed reserves assessments of the Seller's field, even if in a supply contract. Indeed, arguably, if a Buyer is satisfied that the GSPA includes the right liabilities imposed upon and agreed with the Seller, then requiring volume limitations on the Seller should be unnecessary. One of the main reasons for this, is if the Seller 'oversells' from the field and cannot deliver the volumes it has committed to in later years, it will pay shortfall penalties to the Buyer.

Firm vs. interruptible supplies

The terms of volume delivery, as agreed in a gas supply contract, may be firm or flexible. Firm delivery implies an obligation by the producing company or Seller to deliver the specified quantities over the term of the contract. If the delivery obligation is not fulfilled, the Seller may be obliged to pay damages or cover the costs of alternate fuels used by the Buyer. The Seller will only be relieved of its obligation to deliver by Force Majeure (FM).

Flexible delivery obligates the producing company/Seller to make attempts to fulfil the delivery obligation but does not require fulfilment of all the delivery obligations.

Binding vs. flexible volumes

Once the volume framework has been determined (Total, Annual, Daily, Hourly Contract Quantities), and Buyer and Seller understand the needs of each party, it is possible to move ahead with the other volumetric elements of a GSPA. Indeed, at this point in the negotiations, the sides begin to introduce some other binding requirements as well as some volumetric flexibility in their agreement.

Although the flexibility is primarily needed by the Buyer, the Seller also is not averse to providing this, as it wants its customer's facility to be able to remain operational throughout the term of the gas contract. The Buyer also wants to be able to "book" the revenue received on its gas sales, which under certain country legislations, the Seller cannot do if the Buyer has paid for natural gas but not actually taken receipt of the volumes.

Take or Pay

Perhaps the most common volumetric commitment in a gas sales contract is what is known as the Take or Pay (TOP). This is the volume assurance that the Buyer typically agrees to provide the Seller in exchange for the price flexibility it receives from the Seller.

Take or Pay is a provision in a GSPA according to which if the Buyer's annual purchased volume is less than his Annual Contract Quantity (ACQ), minus any Shortfall Gas in the Seller's deliveries, minus any Downward Quantity Tolerance (DQT), then the Buyer has to pay for this volume of gas, as if the gas had been received.

The Buyer may have the right in subsequent years to take the gas paid for but not received, either free or for an amount to reflect changes in indexed prices (Make-Up Gas).

The definition of Take or Pay is:

An x% of the ACQ, less those gas volumes which have not been delivered by the Seller and which he should have delivered, minus the gas quantities that the Buyer was not able to accept due to reasons of Force Majeure by Buyer or Seller, minus what is known as Carry-Forward Gas.

Typically the TOP Quantity is reduced by quantities that: (a) the Seller failed to make available for delivery; (b) were rejected as they did not meet quality specifications; and (c) the Buyer could not take as a result of Force Majeure.

These standard deductions reflect the basic principles that: A Buyer should not have to pay for a commodity that could not be delivered; the Take or Pay obligation only applies to a commodity that meets the required specifications (or which the Buyer accepts even though off-specification); and that force majeure should operate to fully relieve a party of the obligations affected by the force majeure¹⁵.

A key element of TOP clauses is that the Quantity is not fixed but is adjusted to reflect events that happen during the year.

¹⁵<https://www.kslaw.com/blog-posts/key-considerations-energy-take-pay-contracts>

A Take or Pay clause is essentially an agreement whereby the Buyer agrees to either: (1) take, and pay the contract price for a minimum contract quantity of gas each year (the TOP Quantity); or (2) pay the applicable contract price for such TOP Quantity if it is not taken during the applicable year. Most commonly, Take or Pay obligations are determined on an annual or contract year basis.

The Take or Pay clause is activated when the Buyer does not take delivery of the entire quantity of the natural gas ordered (namely his TOP volume which is a percentage of the ACQ). In many cases, the Buyer is required to pay for this minimum quantity of natural gas (which is defined in advance) even if it has not taken delivery of it in the respective year.

The rationale behind the Take or Pay clauses is based on the very nature of natural gas projects, which require huge upfront investments. Take or Pay clauses act as a risk sharing mechanism between the Seller that, having invested significant funds often financed by banks, seeks assurance for a guaranteed income and the Buyer that seeks stability in volume supply and some flexibility on prices. It also follows from the above, that Take or Pay clauses operate as an implied guarantee for the financing of a project by the banks, for which they are, indeed, often the primary collateral¹⁶.

Typically, a Seller is concerned with two fundamental risks: market demand risk and price risk. A Take or Pay clause places the risk of changing or deteriorating market conditions on the Buyer by requiring it to always be responsible for the payment of a minimum purchase commitment, leaving the Seller with only the market price risks to manage, which in some cases may be hedged¹⁷.

Therefore, the original concept and the purpose of the clause is the balanced satisfaction of both parties.

Take or Pay clauses ensure that a Buyer cannot use the contract for freezing natural gas quantities without obligation to compensate the Seller. Furthermore, the Seller is assured an annual fixed income, regardless of whether the natural gas market is eventually profitable for the Seller, thus the downside risk in the natural gas market is passed on to the Buyer¹⁸.

Seasonality - Some contracts also include seasonal, quarterly or monthly Take or Pay obligations. When expressed over shorter durations this type of Take or Pay clause is also commonly referred to as a Minimum Take or a Minimum Bill

¹⁶ <http://www.moussaspartners.gr/Take-or-Pay-clauses-in-gas-supply-agreements/>

¹⁷ <https://www.kslaw.com/blog-posts/key-considerations-energy-take-pay-contracts>

¹⁸ <http://www.moussaspartners.gr/Take-or-Pay-clauses-in-gas-supply-agreements/>

Obligation¹⁹. Buyers are increasingly seeking seasonal deliveries — say as much as 75% in winter, versus 25% through the rest of the year, whilst most suppliers prefer to run their plants at consistent rates year-round, and some may want to capture higher winter spot prices.

For example, many Turkish importers of Russian gas are “burdened” with a Minimum Summer Quantity (MSQ), which is set at around 37.5%. This is a requirement made by Russia’s Gazprom, presumably to ensure the Buyers’ don’t take too high a volume of their annual TOP only during the higher consumption winter months, at the expense of the summer months.

On the other hand, China which has the fastest growing market for LNG, managed to sign winter-heavy long-term contracts for winter 2018/2019 supplemented by winter-strips, to prevent a situation similar to their 2017/2108 winter gas shortage. This also meant that it was less urgent for China to buy spot volumes, including spot US LNG cargoes as it did the previously year when it importer 26 US cargoes over November 2017 to March 2018 amid severe supply tightness in the Pacific basin.

Japan, China and South Korea often schedule additional term deliveries in winter, when demand normally peaks, which limits their ability to ramp up spot purchases quickly to take advantage of tanking prices. But because Taiwan's demand tends to peak in summer, it has more spare tank capacity available in winter.

Certain contracts can provide different levels of Take or Pay during different periods of the contract. For example, a lower Take or Pay could be offered to projects during the first few years, when theoretically it is more difficult for new power stations to precisely predict their volumetric needs. Even for those IPPs that will already have been operational for several years with gas from one source, having later on two different gas suppliers may require some tactical planning by them. Thus, enabling such a Buyer to have a lower level of TOP during the initial period of the new contract, increasing gradually over the contract term, may be of benefit to the Buyer and may help the Seller to clinch a deal.

In the normal course of events, Buyers want as low a TOP as they can negotiate (as this provides optimal flexibility), whilst Sellers want as high a TOP as possible (as this enables minimum over-capacity investment).

¹⁹ <https://www.kslaw.com/blog-posts/key-considerations-energy-take-pay-contracts>

Often TOP for power plants can reach around 70%-80% of the ACQ, and the stations will want flexibility on their Make-Up Gas (term defined below) to match as closely as possible their power dispatch structure. LNG liquefaction facilities, especially those belonging to major corporations, that are buying feedstock gas to liquify and ship to clients around the world, can go up as high as 95% or even 100% TOP (as long as they have a Max/Excess Gas clause).

A TOP that is too high and does not allow Buyers to take Make-Up Gas is certainly problematic for a power generating facility and could even cause difficulties to an LNG facility. Counterintuitively, too high a Take or Pay could also be problematic for the Seller.

Indeed, although a priori, an inexperienced Seller may feel that a TOP clause enables it automatically to “have the cake and eat it also” (namely get paid for the gas, not deliver it to the Buyer and have the ability to sell it to another Buyer and benefit from a double dipping), this is not as straightforward as would appear.

The reason for this is that in many legislations, Sellers may not be able to “book the money received” until the gas has been actually delivered, and/or there may be requirements on Seller to pay back some of the value of the aggregate Make-Up Gas (see below) at the end of the contract, if this gas was never taken by the Buyer.

In addition, the Seller has to preserve any Take or Pay gas for each specific client, even if this gas has not been taken in any particular year by a specific client, since the gas has been paid for. However, the Seller does not have to preserve even this volume forever, but rather only in accordance with the terms of the contract. These terms are stated in the Make-Up Gas clause (see below), which usually states that the Buyer has the right to recover the gas it has paid for but not taken, within the next x years (potentially 1-3 years, but could be as long as 5). Thus, after this period, the Seller can sell this gas to another client.

Case: Tamar Take or Pay (Israel)

In 2017, the Electricity Regulator in Israel namely the Public Utility Authority (PUA), made claims that since there was only one gas field online in Israel (namely Tamar), that the state electricity utility, Israel Electric Corporation (IEC) should not be obliged to a high level or even any Take or Pay quantity and should just consume whatever volumes it wants. The PUA claimed that this would be justified since IEC would not be able to use/abuse this low/minimal level of TOP term in order to take gas from another gas field, or from spot gas, since there is no such other field in production and the only alternative available to Israel was higher priced LNG.

However, this is a mistaken and dangerous precedent to adopt, and Sellers should not agree to this. It would enable IEC the freedom to take as little gas as it wants depending on other sources of energy available such as coal or potentially lower priced LNG if the global markets fall that low. In addition, it would enable the PUA to dispatch IEC's stations behind those of independent power producers (IPPs), that have a lower gas price in Israel.

Case: IEC Take or Pay

Going forwards In Israel after 2020, Buyers may feel they could depend on the market once Leviathan comes on line and just buy gas on the spot market or enter into short-term contracts, rather than entering into additional long-term contract(s) with TOP obligations.

This is in fact what IEC is counting on and acting upon as it remains on the sidelines and has not entered into any additional GSPAs since the one it signed with the Tamar field in 2012.

However, Israel is far from being a "mature market", even after Leviathan comes on line at the end of 2019, followed by Karish in 2021 (plus spot imports of LNG which will still be available).

A "market" is usually described as one that would include 10 separate sources of fuel, it requires depth and it requires the supplies to be in different hands for there to be liquidity, secure availability and diversity of contract terms. IEC as the State utility electricity provider, and the essential service provider should desire, and/or be obliged to buy its gas from at least three separate sources. No coal supplier supplies more than 20% of IEC's coal consumption.

Take or Pay clauses may appear quite onerous on a Buyer, but in actual fact they are less onerous than the requirement to take the ACQ, as the Buyer is given the option not to take the full ACQ each year. This is a reasonable requirement as indeed it is tricky for a consumer to make a precise gas consumption forecast for many years forward, due to complex technical issues over the long term.

In addition, once the TOP Quantity has been agreed, the sides then add some extra degree of flexibility in allowing the Buyer to take the gas, it paid for but not taken, later on (Make-Up Gas).

Importantly, the Buyer is not in breach or default of the contract if it fails to nominate or take delivery of the TOP Quantity in any applicable year. Often a Buyer has the right to nominate zero deliveries in a year and this would not be a breach or default. Instead, the difference between the quantity actually taken by the Buyer during that year and the corresponding TOP Quantity will form the basis of a deficiency quantity for which the Buyer becomes obligated to make a Take or Pay payment to the Seller at the end of that year.

Run-in or commissioning period

A run-in/commissioning period is a period during which the Buyer has no TOP obligations, which puts the Seller under additional risks. This normally brings the parties to ensure that this period is no longer than 3 months.

Make-Up Gas (MUG)

Most GSPAs contain a Make-Up Gas provision. This allows a Buyer's TOP obligation to be averaged out over the life of the contract. Once a Buyer has made a TOP payment, and if it has not taken all the sales' gas, then these volumes will go into a Make-Up bank. If at some point in subsequent years, the Buyer has taken the TOP amount for that year before the year-end, and if it requires more gas during that year, it can start taking gas free of charge from the Make-Up bank, up to the volume of the Make-Up outstanding.

Make-Up Gas (MUG) is gas for which a Buyer has paid under its Take or Pay obligations but not taken and may have rights to receive in subsequent years for no further charge or at reduced prices, in the form of credit, after it has taken gas in excess of an agreed threshold volume (usually next year's TOP volume).

A Make-Up is a right which entitles the Buyer to apply sums paid for gas not taken as a credit against payment liabilities in respect of gas delivered in

subsequent Take or Pay periods, usually when it takes delivery of more than the minimum quantity.

Thus, Take or Pay options are often paired with Make-Up Gas provisions. This is the right of the Buyer, who in any contract year may have taken less than its TOP gas, but has made its TOP payment, to take in subsequent years, without payment or with reduced payment (depending on what has been agreed in the GSPA) a quantity of gas equal to the volume not taken.

The following year, if and when the Buyer has reached its TOP level (namely if its TOP is 75% of its ACQ it will have met its TOP commitment by day 273 within the year, namely on the 30th September if it nominated volumes equally throughout every day of the year), (or another minimum quantity level as may be agreed in the contract).

In relation to each Contract Year at the beginning of which there exists any Make-Up Aggregate, then as from the Day on which the Buyer has first taken delivery of, and paid for, a quantity of gas equal to the TOP Quantity in respect of the relevant Contract Year, the Buyer will receive any subsequent deliveries of gas during such Contract Year free of charge (and not at the Gas Price) up to the balance of such then outstanding Make-Up Aggregate.

Thus, the Buyer will be entitled to exercise the right to have delivered at the delivery point an equivalent quantity of sales gas, for which a Take or Pay Payment has been paid (but the gas not taken) without the Buyer having an obligation to make a payment in respect thereof ("Make-Up Right").

Recovery of Make-Up Aggregate could include the following clauses / be worded as follows:

In relation to each Contract Year at the commencement of which any Make-Up Aggregate exists, the Buyer shall receive a quantity credit (in MMBtu) in respect of any Specification Gas taken and paid for by the Buyer in excess of [**] in the relevant Contract Year up to the balance of the then outstanding Make-Up Aggregate; or whenever any Make-Up Aggregate exists, then the Buyer shall receive a credit in respect of any gas taken by the Buyer in excess of the Minimum Quantity in the relevant Contract Year up to the balance of the then outstanding Make-Up Aggregate. Such credit shall not exceed an amount in MMBtu equivalent to [x%] of the ACQ for such Contract Years.

The quantity credit mentioned shall be converted to a monetary credit by multiplying such quantity with a price equal to the Contract Price applicable in respect of the Contract Year in which such Make-Up Aggregate is recovered, together with interest thereon at the rate [x%] from the day (or if applicable, from each of the days) on which the Buyer made payment in respect of gas taken by the Buyer in excess of the Minimum Bill Quantity in the relevant Contract Year (which is subsequently deducted from the Make-Up Aggregate), until payment of the relevant credit amount.

The quantities to be used in so reducing the Make-Up Aggregate shall be established by applying the 'first in, first out' principle to the quantities constituting the Make-Up Aggregate.

The monetary credit calculated shall be taken into account in the Annual Reconciliation Statement in respect of such Contract Year and to the extent that the sum due from the Buyer to the Seller is less than the amount of such credit, the Seller shall refund the balance to the Buyer; any such credit to the Buyer shall be deemed to be a recovery of Make-Up Aggregate by the Buyer to the extent of the quantity corresponding to such credit and the outstanding balance (if any) of Make-Up Aggregate shall be reduced commensurately.

Any Net Annual ToP Quantity paid for in respect of a Contract Year together with the Net Annual ToP Quantity in respect of the previous Contract Years which has not already been recovered shall be known as 'Make-Up Aggregate' for the purposes of the next following Contract Year and the Buyer will use reasonable endeavours to recover such Make-Up Aggregate, as soon as and to the greatest extent practicable, in accordance with the terms of the Agreement.

Case: What if the Seller wants MUG Aggregate to be converted into monetary credit and Buyer says it wants it to be only delivered as gas volumes?

This appears to be 'swings and roundabouts', depending on the pattern of gas price movements during the time MUG is accumulated versus when it is recovered.

Usually, it is more sensible to have MUG aggregate based on volumes of gas paid for, not monetary value.

In practice, the Buyer asks the Seller to supply it the gas it had already paid but has not taken/used before. This of course introduces an important element of flexibility for the Buyer.

From the Seller's point of view, although it has received the money, since it has not provided the "goods", from an accountancy point of view, it is faced with a quandary. As stated previously under the TOP chapter, many countries' monetary regimes do not allow this money to be "booked" until the gas has either been provided or the GSPA contract has come to an end (namely, the Seller has received the cash but not the income).

In addition, the Seller understands that it is unreasonable not to give this added flexibility to its client. It doesn't want its clients to go bankrupt, nor if the TOP clauses are too onerous, does it want its clients to take it to court, as despite protections and the fact that TOP clauses are often enforced, courts are also loath to enforce clauses which could be deemed to be punitive in nature. Thus, the parties reach an agreement to enable the Buyer to set aside a "gas bank" which starts to fill up with MUG.

Interestingly, it is also in the Sellers' interest to ensure that the GSPA includes a Make-Up right for the Buyer, as it will make the TOP clause more enforceable should the Buyer be in default and then try to claim that the TOP payment should not be enforceable because it is too burdensome. Even though neither English nor US courts have taken the position that the presence of a Make-Up right is a requirement for an enforceable Take or Pay clause, it is widely agreed that the existence of a reasonably crafted Make-Up right does make it much harder for a Buyer to later assert a defense claiming the TOP clause amounts to an unenforceable penalty.

Indeed, the inclusion of burdensome conditions or barriers to the Buyer's ability to receive Make-Up quantities, such as overly restrictive time periods during which the Buyer can access this "bank" or notice requirements that the Buyer has to provide to the Seller, could cut against the use of Make-Up rights as a defense in case the issue goes to court. Even if a Take or Pay clause can somehow be shown to amount to a penalty (which both English and US courts still recognize may be possible in some settings), such a finding is not a defense to the Buyer's liability under the contract, but it instead affects the type and measure of damages that are available to the Seller in the event of the Buyer's non-performance.

As stated, Make-Up aggregate (just like Carry-Forward aggregate) accrued by the end of each year can be used only during a limited period following its accrual. Buyers will want to negotiate a period as long as possible and certainly longer than

two years, the more so the higher the TOP figure, as there is more chance of Buyer incurring TOP and less chance of it using any Make-Up gas, if the period is too brief.

Un-used MUG

The Buyer requires a special treatment if throughout the whole term of the contract, it never needs and/or is able to take this Make-Up Gas. Thus, the Make-Up right can either cease to be available on termination of the GSPA term or could continue, but only to the extent that there is sales gas to satisfy this condition, or could outlive the GSPA agreement by a couple of years, if this has been agreed in the contract. Thus, the sides usually include in the GSPA a clause that says that as long as the Buyer has not taken its Total Contract Quantity (TCQ) and has Make-Up Gas available, the contract can be extended by a couple of years to enable the Buyer to take its MUG. Even if the original GSPA does not include such a clause, it is often revised later on to enable the Buyer to have this extra flexibility, if this problem is encountered.

Case: What happens to any Make-Up Aggregate not taken at the end of a contract term?

Usually, as long as the Buyer has used reasonable endeavours to recuperate its Make-Up gas during the term of the contract, the term of the contract will be extended, to a certain degree, to enable it to recuperate the gas at this later stage.

Such a clause could be worded as follows:

If at what would otherwise be the end of the Contract Period there is any Make-Up Aggregate outstanding, then:

- If such outstanding Make-Up Aggregate **exceeds** [**] MMBTU, then the Agreement shall not terminate on that date but shall continue in full force and effect for a number of Days equal to the Make-Up Aggregate divided by the DCQ or [twelve/twenty four (12-24) months] (rounded up to the nearest whole number), whichever is later so as to enable the Buyer to recover the outstanding Make-Up Aggregate in accordance with the terms of the Agreement;

or: provided that in no circumstances shall any such extension of the Term exceed 12-24 Months. (The Buyer will want 24 months; the Seller will strive for only 12 months);

or: If such outstanding Make-Up Aggregate **does not exceed** [**] MMBTU, then on the fifteenth (15th Business Day of the month immediately following the month in which such termination occurs, the Sellers shall pay to the Buyer a sum of money equal to such outstanding Make-Up Aggregate multiplied by the Contract Price in force at the end of the Contract Year in which the termination occurred.

During any such extension the Properly Nominated Quantities (up to the Make-Up Aggregate) shall be made available for delivery by the Sellers in accordance with the Agreement and free of charge and upon expiry of such extension the Buyer shall have no right to recover such Make-Up Aggregate and the outstanding balance shall be reduced to zero.

Often Make-Up Gas will be the Buyers' sole remedy in respect of Sales Gas paid for but not taken. Usually Make-Up rights cannot be exercised in respect of Excess Gas.

Case: Under what circumstances of termination of a gas contract, does a Seller have to repay outstanding Make-Up gas and Shortfall discounts to Buyer?

The less flexibility the Buyer has to take its MUG during the term of the GSPA, the more requirements there will have to be to enable Buyer to cash-out the unrecovered MUG at the end of the contract. This in itself represents a potential problem for the Sellers, again re-enforcing the mutual benefits of having flexible TOP and combined MUG clauses.

Some GSPA contracts allow repayment of outstanding Make-Up to the Buyer after 'normal' termination i.e. after expiry of the contract term.

However, sellers should resist agreeing in the GSPA to the Buyer having unrestricted cash-out of Make-Up Gas on normal termination of a GSPA, because of the optionality such a right provides to the Buyer throughout the term of the contract (namely, the optionality not to take this TOP volume).

A 'default scenario' by the Seller is one such scenario that would require Seller to enable Buyer to cash-out.

Termination after extended period of Force Majeure is another scenario where repayment would be the norm.

Thus, if possible, Sellers should try to restrict their requirement to make a cash repayment for MUG not taken by Buyers at end of the contract term to only the two following circumstances: (1) default by the Seller, and (2) extended FM by either party.

Case: A GSPA where the Buyer has a 100% TOP obligation and no Maximum Daily/Annual Quantity above its ACQ

The GSPA in question, was one where the Buyer (an LNG facility) had a commitment of 100% TOP, although the contract contained no MDQ/MAQ optionality. The question is whether this was a reasonable offer to make by Sellers to Buyer, even though at some point the Buyer was apparently willing to agree to this?

The Seller in the above case, was extremely satisfied at having achieved the 'coup' of getting 100% TOP.

However, under the above condition, the Recovery Day can never be reached by Buyer in time to recover any MUG, and so this would put both sides in a difficult situation.

Points to remember:

- Since the GSPA contained no MDQ/MAQ, the Buyer cannot raise its take of gas above its annual contract quantity on any day of the year, so Buyer is limited to take the DCQ on every day of the year and nothing above this level.
- Since the Take or Pay quantity for each year is 100% of the ACQ, therefore the only point at which Buyer reaches its TOP level for the year is on day 365, namely the final day of the year (December 31st).
- Therefore, there is no ability for Buyer to recover any Make-Up Gas, unless the Buyer has a firm right to Maximum Daily Capacity which

enables him to go beyond its ACQ. Thus, even for an LNG facility, this could be (although not necessarily so) a somewhat difficult condition to meet.

Case: Lower TOP vs. MDQ

What is preferential for Buyer and/or Seller if the Buyer is an LNG facility: that the Seller offer the Buyer a lower TOP (than 100%) or enable Buyer to have MDQ rights?

An LNG facility in country “A” with a nameplate capacity of 15 bcm/year enters into its first GSPA negotiations with a gas supplier from neighbouring country “B”. The GSPA is for 7 bcm/year, with a 100% TOP. The agreement between the parties does not allow the Buyer to have any MDQ rights. The 7 bcm/year is a significant volume of gas and represents an anchor client for the Seller, enabling it to reach FID to develop its gas field.

At a certain point during the negotiations, the Buyer asks the Seller to reduce its TOP to 90%, claiming that without any flexibility to reduce and/or increase its ACQ (i.e. either lower TOP or some MaxDCQ/ACQ, it might remain with MUG that it might be unable to take.

Under these circumstances, the Seller should consider whether to acquiesce to Buyer’s request for a lower than 100% TOP and what are its alternatives.

Since LNG facilities in general are able to operate with a high level of TOP and since this LNG facility in particular has a nameplate capacity far larger than the 7 bcm/year under negotiations (namely 15 bcm/year), the 100% TOP should not represent any problem for the Buyer to absorb. If the Seller gives-in to Buyer’s sudden demand to reduce its TOP from 100% to 90%, at some point, this concession might be used by the Buyer if in the future it suddenly has access to lower cost and/or ‘politically easier’ gas from its host country and/or another neighbouring country. Under such circumstances, the Buyer would immediately reduce its offtake volume from country ‘B’ in favour of the alternative source of gas.

There is thus no advantage (or necessity) for the Seller to give in to Buyer’s request to lower its TOP. If the Buyer nevertheless insists on having some level of volume flexibility (a reasonable request as expressed above), the Seller should instead offer Buyer a firm right to MDQ. This would enable Buyer to take

any MUG that it might accumulate and would protect the Seller from the Buyer favouring another source of gas in the future. Namely, the Buyer cannot reduce its volumes, but has the flexibility to take more on certain years if it fell short of offtaking certain volumes on previous years.

Case: Buyer's ability to take MUG before reaching TOP

Sometimes a Buyer may, under certain circumstances, try to include in its GSPA a demand to have more flexible MUG rights. For example, Buyer may ask that it could take its MUG in the following year once it has reached 50% TOP, rather than after its regular TOP level.

Seller should resist agreeing to this, as that would mean that the following year, the Buyer gets "free" gas once it has reached the lower level of TOP and it would negatively impact Seller. Sellers should push back on such demands and insist that normal Make-Up rights apply to all categories of gas to be recovered, regardless of the reason why this Make-Up Gas has been accumulated, namely only after the normal x% of ACQ (agreed TOP level) has been taken and not at any lower level.

Case: If there is no ACQ and only a DCQ or even a range of DCQs in the GSPA – how does this affect the TOP? What impact does this have on the Buyer and on the Seller?

The Buyer needs to check if the ACQ is defined as the sum of all the DCQs, and if this is the case, then the ACQ level is known and the TOP can be set. However, if there is a range of DCQs, then it is not possible to define a clear ACQ. Without a clear ACQ, it is not possible to set the TOP obligation.

Under such circumstances, it becomes necessary to understand what the GSPA states insofar as the Buyer's nomination rights/obligations; what is stated insofar as the Buyer's Make-Up rights and what this allows it to do, and when Buyer can take its MUG (end of the year, end of the month, etc.).

A GSPA without a fixed known ACQ and/or a range of DCQs, is in fact paramount to there being a daily TOP. If the daily nomination is in the hands of the Buyer, Buyer has to make sure it nominates every day exactly what it needs. If the Buyer can change its nomination on the day itself - or even better for the

sake of the buyer - mid-day, then the Buyer really gets exactly only the volume it wants, and under such circumstances it would have de facto 'zero TOP obligations'.

However, if the Buyer does not know exactly what it needs every day, and/or if it cannot easily change its nomination on the day/mid-day, then this would mean that the Buyer would have to take whatever gas it has nominated on the last date when the daily nomination can be done based on the contract terms. Under such circumstances, the Buyer would have to take any quantity of gas it nominates at this point, and so its TOP is 100% of its final nomination. This would be very restrictive and does not offer the Buyer the ability to reduce its volume.

In many cases, (e.g. Greece buying gas from Russia), the supplier Gazprom does not allow intra-day re-nominations, and this in turn does not allow gas shippers to adjust inflows in case demand forecasts change.

For the Seller this is also problematic, because if the Buyer has at a later date the option to buy cheaper gas from another source, it could reduce its daily nomination to the minimum DCQ level permitted in the GSPA, without the Seller having any recourse.

It would seem that such a lack of ACQ and thus inability to set the TOP would be in favour of the Buyer, but this depends on what is stated regarding Buyer's nominations. In general, this kind of contract is very difficult to work with, as it is difficult to manage the volumes.

Such a clause really leads to layers upon layers of difficulties.

Carry-Forward Gas

There are in general, at least two other types of volume flexibility given to the Buyer. The first is a Maximum Daily and/or Maximum Annual Quantity (MDQ or MAQ), as well as Excess Gas which enable Buyers to take more gas than their daily/annual quantity. The second is a term known as "Carry-Forward Gas", both of which have already been mentioned above in a different context and are explained below.

Carry-Forward is the ability to offset payments for gas taken above the ACQ volume in the current year, against Take or Pay volumes in subsequent years.

In years where the gas taken is greater than some reference level (typically ACQ) the Excess Gas is added to the Carry Forward Aggregate. In later years, this Carry Forward gas can be used to reduce the Minimum Bill for that year.

The definition of Carry-Forward is:

Carry-Forward is a provision in GSPAs by which a Buyer, that takes more than its ACQ or Take or Pay gas (depending on what is agreed in the contract: more commonly above ACQ) in any given Calendar Year, is allowed under conditions defined in the contract, to offset this volume against its ability to undertake the same volume of gas in subsequent years.

In a Gas Sales Agreement, if a Buyer takes more than the agreed reference volume of gas in any year, it will then receive a credit for overtake. This is aggregated with all overtake credits from previous years as a **Carry-Forward Balance**.

Thereafter, if the Buyer takes less than its TOP amount in any subsequent year, it can then reduce its TOP liability by the amount of the **Carry-Forward Balance**. In this manner, it does not accumulate additional TOP volumes that it has to take.

A Carry Forward clause works exactly opposite to the Make-Up clause. It pre-supposes a reward for the Buyer, that at a particular period took and paid for quantities above the agreed limit, thus allowing it the right to transfer the volume taken above the contracted quantity to the next periods, in order to bring the quantity it has taken to its TOP threshold. If a Carry-Forward provision did not exist in the contract, under-taking volumes of gas might have otherwise incurred some form of sanction on the Buyer, such as its Take or Pay requirement.

If, in a given contract period (often a year), a Buyer has taken more than the annual contract quantity (ACQ) then, if there is no accumulated Make-Up Gas requirement, the Buyer can Carry-Forward this excess volume for future use.

The Buyer may use the Carry-Forward to offset the Take or Pay obligation, although there may be a limit to the amount of Carry-Forward allowed in any given contract period²⁰. Indeed, GSPAs are often limited in the amount of gas that can be Carried Forward in any given contract period. An acceptable maximum level of

²⁰ <https://www.risk.net/definition/carry-forward>

reduction being around 20%-30% on average of ACQ in any given year, thereby reducing the Take or Pay quantity in that year by the corresponding amount.

The wording could be as follows:

In respect of any Contract Year for which there arises an Annual Take or Pay Quantity, such quantity shall be reduced by a quantity of Carry Forward Aggregate not exceeding (**) MMBTU during (**) years.

A Buyer will want to negotiate as high a Carry-Forward as possible, and as long a period as possible during which this can be carried forward during the contract, and certainly longer than one year. The higher the TOP the more years to recuperate the Buyer will want, as the greater is the chance it will meet its TOP every year.

Yet over the life of a gas supply agreement, the Buyer is in effect obliged to take, on average, the TOP quantity applied to the aggregate of the Adjusted ACQs applying in each year.

Carry-Forward is not a feature in every GSPAs.

Maximum/Excess Volumes

Although in a GSPA, the Seller's obligation is to deliver gas up to the delivery capacity level, the Buyer will generally have some rights to request higher volumes.

The Maximum- Hourly/Daily/Annual Quantity enables the Buyer to take more gas than its ACQ (up to a certain agreed volume, usually between 105%-120% of ACQ) and usually at the same price as the contract Gas Price. Namely, the Buyer neither has to pay a premium for having unilateral access to this higher volume of gas, nor to commit to this extra volume.

Max and/or Excess volumes of gas do not affect (i.e. do not increase) the Buyer's TOP obligations.

The Buyer's ability to take volumes of gas in excess of its ACQ, has the added advantage in that it often enables the Buyer to reach its TOP levels earlier on during the year (since the TOP is a fraction of the ACQ and not of the MaxACQ). It is thus easier for the Buyer to recuperate any accumulated MUG.

The Seller is usually required to have to provide these volumes of gas, under best endeavours. A "best endeavours" is a phrase commonly found in commercial contracts that places upon the party giving such an undertaking the obligation to

use all efforts necessary to fulfil it. A best endeavours policy places a party under a stricter obligation than "reasonable endeavours."

Sometimes GSPAs include a firm obligation by the Seller to provide such volumes (rather than just a best endeavour), if the Buyer wishes to take such volumes.

Excess gas

Excess Gas is gas, that the Buyer may ask the Seller to deliver above the delivery capacity rate and above the Maximum Quantity (MaxHQ/MaxDQ/MaxACQ). The Seller does not have to do so but, if it does, the Buyer will usually pay a premium over the main contract gas price.

The Seller's obligation to deliver excess gas will be generally on a "reasonable endeavours" basis (namely a lesser obligation than best endeavours). Excess gas will normally be paid by the Buyer at a premium to the normal contract Gas Price. Thus, while the Seller is under no obligation to provide this additional volume of gas, the negotiated premium price provides the Seller with an incentive to provide it, if it is able to. Indeed, if a gas field is primarily a dry conventional gas field, Excess Gas should be sold at a premium, as Buyer is getting access to higher volumes, without having to incur TOP. In the negotiations, the Sellers should hold out for a price above the Gas Price, of at least 10%.

The clause could be worded as such:

Buyer may at any time nominate additional volumes of up to (**) MMBTU above the applicable MaxHQ ("Excess Gas") and Sellers shall make reasonable endeavours to comply with such nomination of additional volumes. For the avoidance of doubt, Excess Gas nominated by the Buyer shall not be considered a Proper Nomination.

Thus, if the Buyer is entitled to nominate up to [120%] of DCQ on any day (namely this would be its MaxDQ), then Excess Gas would be any quantity greater than [120%] of DCQ.

Sometimes it is the Seller that asks to be allowed to provide Excess Gas, which the Buyer should/could take. Under such conditions, the Seller should provide the Excess Gas at a cheaper price than the agreed contract Gas Price. Depending on

what has been agreed in the GSPA, the Buyer either has to take this Excess Gas or has to make best/reasonable endeavours to take it.

Usually Excess Gas taken cannot be regarded/counted within the framework of Make-Up Gas rights. Namely, taking Excess Gas does not reduce the aggregate Make-Up Bank that the Buyer still has to take if he has failed to take all his TOP gas in any given year(s).

It should be added, that the TCQ stated in the GSPA, includes any Excess Gas that may be taken, since the Buyer is just taking gas early. Namely, Excess Gas does not increase the TCQ, but is part of it.

Case: Right of first refusal (ROFR) for daily Excess Gas.

A Buyer may be seeking rights of first refusal to receive long-term additional volumes (Excess Gas) on the same terms as its existing tranche of gas.

If the Buyer is making such a request, the Seller needs to realize that this is not really Excess Gas but a form of Buyer's Option, which the Buyer is trying to get without having to pay any premium on this. Typically, such options cost something as the Buyer is getting value.

Offering (or not) the Buyer ROFR to receive Excess Gas is a purely commercial call for Seller. Short-term daily Excess Gas should only be offered as ROFR if Buyer is prepared to pay a significantly higher price than its Gas Price. Otherwise Excess Gas should be purely at Seller's option but should still be sold for higher than the Gas Price.

From the Seller's point of view, the advantage of this gas volume over 'normal' Excess Gas is that the TOP level in the GSPA would rise in line with the new DCQ.

Another option to think about, as a way for Seller of securing an outlet for future sales, is a Put/Call structure with Seller having the right to 'Put' an agreed volume at a price of x% below the Gas Price and the Buyer having the right to 'Call' same volume at y% above Gas Price, all within an agreed time frame.

Downward Quantity Tolerance & Upward Quantity Tolerance

The option by the Buyer to buy less gas, known as Downward Quantity Tolerance (DQT) or more gas known as Upward Quantity Tolerance (UQT) than the Annual

Contracted Quantity. The Buyer has to take a reverse action in the next years to compensate for the different amount. Namely, the actual ACQ agreed needs to be delivered over the life of the contract²¹.

The Downward Quantity Tolerance (DQT) is the amount by which a Buyer may fall short of its full Annual Contract Quantity in a Take or Pay gas sales contract without incurring sanctions, while Upward Quantity Tolerance is the amount that it can take above said quantity, often in the range of 5%-15%.

If there is no provision requiring the Buyer to take supplementary volumes in subsequent years to make good for the deficiency, the Annual Contract Quantity becomes in effect the ACQ minus the DQT.

Under current market conditions where there is often a discrepancy between gas prices in term contracts and spot prices, depending on circumstances and seasons, Buyers, including Buyers of LNG, often try to reduce their long-term purchases if the spot price is lower than their contract price. A good tool to do so is by them activating Downward Quantity Tolerance clauses in term contracts and buying more spot gas, when these provide better / cheaper alternatives.

Cheaper spot prices relative to term prompt interest from end-users, but actual purchases hinge on factors such as available storage space and regasification slots, contract flexibility to reduce or divert term offtake, and shipping availability.

While Buyers may exercise tolerance clauses in long-term LNG contracts to maximise purchases on the cheaper spot market, demand for re-stocking may allow spot Sellers to push prices up near to long-term contract levels, thereby avoiding any downward pricing pressure resulting from the reduction in post-winter gas burn as temperatures warm in the northern hemisphere.

Usually, the key source of offtake flexibility for the Buyer is the Downward Quantity Tolerance (DQT) specified in the GSPA. The DQT is the portion of the contract's Annual Contract Quantity (ACQ) that the Buyer is allowed to forego in a given annual delivery period, without payment. The remaining portion of the ACQ is the Take or Pay (TOP) quantity. The Buyer is still required to take delivery of the TOP quantity, or to pay for it as originally scheduled, followed by the receipt of Make-Up quantities at a later date (unless the Seller lets them off the hook). Therefore,

²¹ https://research-doc.credit-suisse.com/docView?language=ENG&format=PDF&source_id=csplusresearchcp&document_id=1052737581&serialid=e%2FPOFGbdN4IZXgBhUHiQ8Vd92B84hIzZ3flbMZuLUC8%3D

DQT flexibility can be thought of, and modelled as, a series of annual put options, and the larger the Take or Pay (TOP) component of the ACQ (i.e., the smaller the DQT), the smaller the option value held by the Buyer.²²

As markets become more a Buyer's market, DQT's are returning to levels near the upper end of their historical 0-15% range (generally DQT allows cuts of around 10% in scheduled annual deliveries), and in some cases they are even moving above it. Also, Buyers are benefiting from more liberal life-of-contract caps, which limit the total DQT flexibility exercised over the entire term of the contract and have historically ranged from 50% to 100% of the ACQ.

Upward Quantity Tolerances (UQT's), which allow the Buyer to take extra quantities above the ACQ level, are now back on the table as well. When present, these UQT's represent call options whose value should be incorporated in deal valuation.²³

Qatar contracts often provide Buyers with a lot of flexibility in terms of upward and downward tolerance and scheduling.

How practical are DQT and UQT clauses?

One problem with DQT clauses for LNG Buyers is that notice periods can often be lengthy with some sales and purchase agreements in Japan often requiring even one year's notice, although that is dropping to as little as one month as deals become more flexible.

Example: An example of the difficulty in enforcing UQT/DQT clauses was seen in the case where TEPCO had to procure additional natural gas when its nuclear capacity became unavailable after the Fukushima Daiichi nuclear disaster.

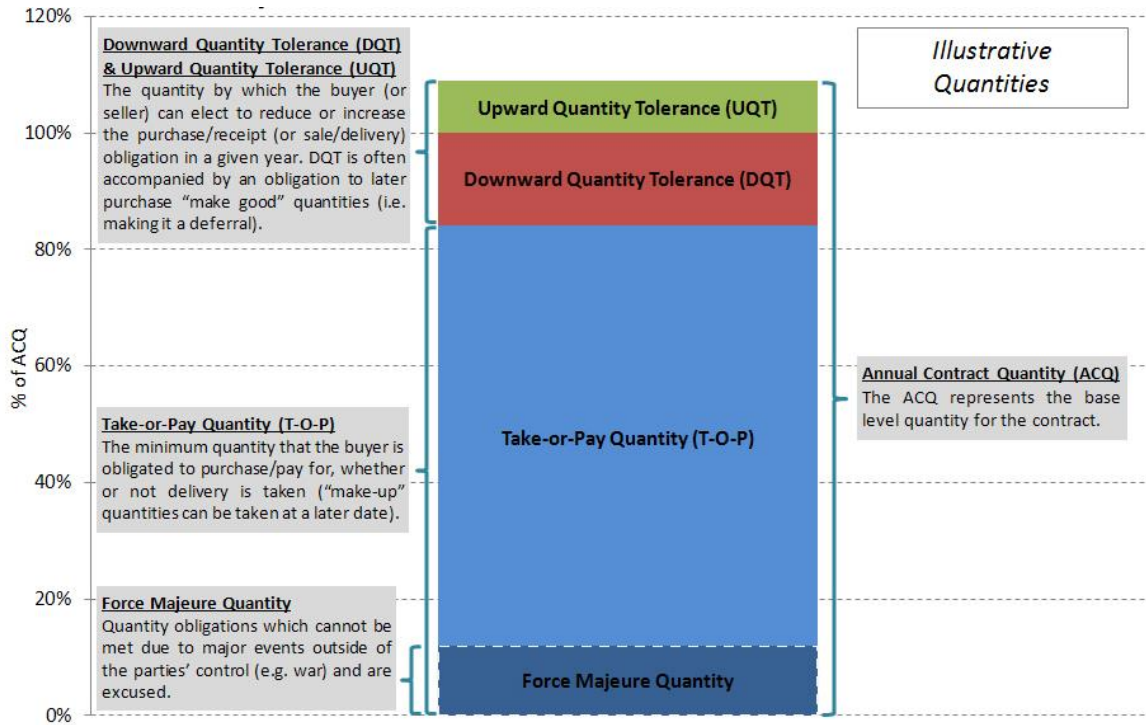
Spot prices immediately shot up and TEPCO was keen of course to buy as much gas under its term contract price as possible but found that this was not as easy as it had thought when signing the contract.

Indeed, unexpected variations in demand can occur after fixing ADP (annual delivery program) arrangements. GSPAs incorporate UQT/DQT clauses explicitly for this purpose, but in actual fact, some gas projects make sales to third parties which prevent the clauses from being put into practice. It is for this

²² <https://capraenergy.com/capra-energy-journal/lng-market-offering-more-favorable-offtake-provisions-for-Buyers>

²³ Ditto

reason, that Buyers want to enter into purchasing agreements with plant facilities and LNG ships that have an appropriate level of excess capacity, in order to ensure that the flexibility in the contract is actually a practical option.



24

Shortfall Gas

Shortfall Gas is gas which was properly nominated by the Buyer (beyond the annual agreed upon permitted deviation of 2%-5%), but was not delivered by the Seller, except for reasons of Force Majeure.

All gas that is taken by a Buyer, even those volumes of gas that it might take for which the quality fails to meet the Specifications, shall not be part of the Shortfall Quantity. Any gas that fails to meet the Specifications, and which was rejected by

²⁴ Author redone from: <https://capraenergy.com/capra-energy-journal/lng-market-offering-more-favorable-offtake-provisions-for-Buyers>

the Buyer (in accordance with the relevant clause regarding gas quality) shall for the purposes of determining Shortfall Quantity be considered as not having been made available by Sellers.

If the gas Seller fails to deliver a proper nomination to the Buyer, then the quantity not supplied, which exceeds the daily operational tolerance, will be considered Shortfall Gas and the Seller will supply an equal quantity of such Shortfall Gas in the following month at the Shortfall Gas Price.

The Shortfall Gas Price should be at a discounted price (50%-90% discount rate, depending on how the sides manage their negotiations) of the Contract Gas Price. For example, if the Shortfall Gas Price is 65% of the Gas Price, any Shortfall Aggregate accumulated is supplied in the next month at a 35% discount to the Gas Price. Thus, the next month, the first gas that the Buyer takes is its shortfall gas from the previous month, at the lower Shortfall Gas price.

The clause could be worded in the following way:

In circumstances where a balance of Shortfall Aggregate exists at the beginning of a month, then the first gas delivered during that month, which would otherwise be paid for at the Gas Price will be paid for by the Buyer at the Shortfall Gas Price, and the Shortfall Aggregate shall be reduced by the amount of gas which is paid for at the Shortfall Price.

Accumulation of Aggregate Shortfall

To the extent that at the end of any month there is Shortfall Aggregate remaining unrecovered, then such remaining balance of Shortfall Aggregate shall be carried forward and added to any Shortfall Aggregate for the following month(s) (as the case may require).

Cash-out payment

In certain circumstances, if the Shortfall Aggregate accumulates to a large volume of gas and/or extends over a long period, the sides may agree that the Seller has to make a cash-payment to the Buyer. Such a clause could be written as follows:

Extensive and/or prolonged Aggregate Shortfall

If any Shortfall Aggregate has not been recovered within x Months (e.g. 2 months) after the end of the month in respect of which it first arose, then, the Seller shall pay to the Buyer for the second such month a sum of money equal to the product of such remaining unrecovered Shortfall Aggregate (expressed in MMBtu) and the difference between the Gas Price and the Shortfall Gas Price, and upon the Buyer's receipt of such payment such remaining unrecovered Shortfall Aggregate shall be reduced to zero.

Or

If at any time or from time to time during the Contract Period, the aggregate money value of the product of the Shortfall Aggregate and the difference between the applicable Shortfall Gas Price and the Contract Price exceeds (**), then the Buyer may by notice to the Seller elect that, subject to the limitations of liability under Article [**], the Seller shall pay to the Buyer a sum of money equal to such aggregate money value and the Shortfall Aggregate shall be adjusted accordingly.

Case: Egypt (EMG) cut of gas supplies to Israel (IEC)

Buyer to receive compensation in form of volume of gas not received, or the monetary difference in the price between the Gas Price and the Shortfall Gas Price

In the GSPA, the shortfall gas price was [x] less than the gas price; (for argument sake let us say that the difference between the Gas Price and the Shortfall Gas Price was \$1/MMBtu). The Seller cut off supplies to Buyer for reasons that are not FM (after dozens of bombings of the gas pipeline between Egypt and Israel, combined by gas shortages in Egypt and a revolutionary change of regime in Egypt).

The GSPA stated that under such conditions, Buyer is only entitled to compensation of \$1 per MMBtu * x volume in MMBtus a year * x years of remaining supply; all capped at a maximum amount.

However, this specific GSPA was backed by a guarantee from the government of Egypt, providing a commitment to supply to Israel all of the volume stated in the GSPA, or damages in the case of IEC having to use alternative fuels in the case of non-supply.

Caps on overall damages, including Shortfall discounts, are not uncommon in GSPAs, and again the final wording in the agreement depends on the relative negotiating strength of Seller and Buyer.

The case eventually went to the International Court, and the court sided with IEC requiring the Egyptian supplier to provide the full amount of damages. It is indeed interesting in this case, that the court took the Egyptian government guarantee as overriding the GSPA terms.

Case: The Buyer is a major international oil and gas corporation buying gas from a small independent oil company (the Seller). During negotiations of the GSPA, the Seller asks Buyer the right to pay back any Shortfall it might have accumulated after 1 year rather than after 1 month

The Seller might solicit from the Buyer to be allowed to make a delayed payment of Shortfall compensation in cash, namely only after 12 months if it has not “repaid” its dues in monthly deliveries of lower priced Shortfall Gas. The Buyer on the other hand might respond by demanding to receive cash payments each month whenever the subsequent month’s quantities of gas are insufficient to repay the Shortfall.

Although the Seller might want to reject the Buyer’s demand for monthly pay out, for cash conservation reasons, this rejection might send the wrong signal to the Buyer during the negotiation’s process. Instead, the small IOC (Seller) would be best served trying to reassure the buy NOC (Buyer) that there will be minimal Shortfall concerns in order to complete the GSPA, rather than elevating this concern.

Remaining Shortfall Aggregate at termination of GSPA term

Often, the Seller's delivery of Shortfall Aggregate (gas volumes) at the Shortfall Gas Price and/or its payments for Shortfall Aggregate and Commercial Default Gas constitute the Buyer’s sole and exclusive remedy for the Seller’s failure to deliver gas pursuant to gas sales agreements. The clause could be worded as:

The delivery by the Sellers of a quantity of Specification Gas to be paid by the Buyer at the Shortfall Price of payment made according to the provision of article [**], shall be the exclusive remedy and the limit of and the sole damages to which

the Buyer may be entitled from the Seller (whether direct, indirect, consequential or otherwise and howsoever arising), in respect of Seller's failure to deliver Properly Nominated Specification Gas to the Buyer in any hour, including as a result of a breach of articles [**]. Notwithstanding the aforesaid, in the event that the Seller is in breach of its undertaking under article [**], the Buyer shall have the right to seek specific performance of such undertakings.

In addition, at the end of the contract term, if all the Shortfall Gas has not been supplied by Seller, then Seller will often only have to pay the discounted price. The wording of such a clause could be:

If at the end of the Contract Period there is any quantity of Shortfall Aggregate which has not been discharged then, subject to the limitations of liability under Article [**], the Seller shall pay to the Buyer at such date of termination a sum of money equal to the product of the Shortfall Aggregate and the difference between the applicable Shortfall Price and the Contract Price at the end of the final Contract Year of the Contract Period.

Seller's Commercial Default

A Commercial Default by Seller would be circumstances where the Seller fails to deliver all or part of the Properly Nominated Quantity for a day by reason of Commercial Default. Such gas would constitute **Commercial Default Gas**.

Commercial Default means any failure to supply gas by the Seller in breach of its obligations under the Agreement which failure is authorised by a member of the board of directors (or other governing body) or chief executive officer (or equivalent person) or the person with overall responsibility for gas marketing operations of a Seller, for the purpose of enabling the Seller to deliver gas to other Buyers on more advantageous commercial terms for the Seller than those available under the Agreement, but excluding actions required by applicable Law.

A Seller may decide to be in Commercial Default because it has given preference to another Buyer for commercial reasons. Under such circumstances, the Buyer should get payment compensation from the Seller. The clause could be worded as such:

In respect of any Commercial Default Gas, in addition to the Shortfall Aggregate compensation, the Seller shall pay the Buyer an amount calculated as the net value received by the Seller from another Buyer for the sale of such Commercial Default Gas; less the sale proceeds that would have been receivable by the Seller under the Agreement if such sale and delivery of the Commercial Default Gas had been made to the Buyer in accordance with the terms of the Agreement.

The Parties agree that the rights of the Buyer set out in the Agreement in respect of a Commercial Default, including the Shortfall Aggregate compensation determined in accordance, may not constitute an adequate remedy. Accordingly, the Parties agree that in the event of a Commercial Default by Seller, without prejudice to any other rights the Buyer may have under the Agreement, the Buyer shall be entitled to seek and obtain injunctive relief against the Seller, including orders of specific performance.

Note: However, such a compensation would have to be capped, as uncapped compensation is not realistic.

Case: Buyer asking to include in the GSPA a right to terminate the contract in case of Commercial Default by Seller

Seller should resist including in the GSPA termination clauses, requested by Buyer, that have no consideration of the volume of gas involved. Namely, Buyer should not be able to terminate for Default by Seller to provide 1 MMBtu of gas, regardless of the severity of the reason for non-delivery.

Indeed, the wording of a termination clause, if a Commercial Default occurs, should for example state “to the extent of the Seller not supplying at least [20%] of the ACQ, as consisting of Commercial Default Gas”.

4.5 Gas nomination procedures – delivery program

Delivery Program means the Hourly, Daily, Weekly, Monthly and/or Annual Nomination Program, as the case may be.

A GSPA will normally lay down a procedure for the time when the daily or weekly, quarterly or annual program (or whatever has been agreed) nomination of gas volumes should be made by the Buyer. It will also specify the Buyer's rights to vary the nomination at short notice and the speed with which the Seller must respond to such changes. It is usually up to the Buyer to nominate the volume of gas it needs, and thus GSPAs usually include a definition which states something on the lines of:

“The Seller shall deliver, and the Buyer shall take delivery of gas under the Agreement during each Contract Year in accordance with a series of programs.”

Proper Nomination means a nomination which has been made which shall:

- not exceed the Maximum Daily Quantity (MDQ); or shall not exceed the applicable MaxHQ;
- not cause the aggregate quantity of gas delivered to the Buyer in respect of any Contract Year to exceed the ACQ in respect to that Contract Year plus any amounts of Make-Up Gas Properly Nominated during such Contract Year;
- be expressed in MMBtu per Day; and comply with the notification requirements under [Clause x];
- not be less than the Minimum Nomination, unless such nomination is zero in accordance, and in circumstances of the Buyer giving notice of x event (such event to be described in the GSPA).

Example of nomination procedure

Annual Nomination Program

By no later than one hundred and thirty (130) days prior to the commencement of each Contract Year, the Seller shall advise the Buyer of the dates on which maintenance of the Seller's Facilities is scheduled to take place in that Contract Year and the following five Contract Years; and any other information which it believes will assist the Buyer to plan its gas off-take and production activities for LNG during the Contract Year and the following five Contract Years.

By no later than one hundred (100) Days prior to the commencement of each Contract Year, the Buyer shall advise the Seller of an estimate of the Buyer's anticipated aggregate gas offtake for that Contract Year; an estimate of the daily quantities of gas which the Buyer expects to require at different times during that Contract Year and any days or periods during which the Buyer expects to take delivery of gas at other than uniform hourly rates during each day; the dates on which maintenance of the Buyer's Facilities is scheduled to take place in that Contract Year and the following Contract Years; and any other information which will assist the Seller in the planning of its gas production and delivery activities.

Monthly Nomination Program

No later than 15:00 on the Wednesday immediately preceding the beginning of each Month, the Buyer shall give notice to the Seller of the quantity of Specification Gas it then forecasts to be required in respect of each day of that month. This forecast is indicative and non-binding.

No later than 15:00 on the Wednesday immediately preceding each week, the Buyer shall give notice to the Seller of the quantity of Specification Gas it then forecasts to be required in respect of each hour of that week. This forecast is indicative and non-binding, or

On or before [•] of each Week, the Buyer shall give the Seller a notice (each, a Weekly Program) setting out the total estimated quantities of gas which at the date of such notice the Buyer anticipates that it will request the Seller to deliver pursuant to a Proper Nomination on each day of the next following week and the anticipated average flow rate applicable thereto and shall give a preliminary indication of such quantities for the two weeks thereafter.

Daily Nomination Program

No later than 15:00 each Day, the Buyer shall give notice to the Seller nominating the quantity of Specification Gas it requires to be delivered at the Delivery Point in respect of each hour of the immediately following day. This nomination will be binding and final, subject to variations [e.g. provided that such notice is given not less than fourteen (14) Hours before the Hour to which it relates and provided it doesn't exceed the MaxHQ]; or

At or before [12:00] on each day, the Buyer shall give the Seller a notice of its Proper Nomination of gas, in each case (if any) for delivery under the agreement on the following day.

No later than 16:00 on each day, the Seller shall inform the Buyer of its ability to meet the Buyer's nominations, fully or partially in respect of any hour of the immediately following day; or

In respect of each day of the Take or Pay period the Seller shall make available for delivery at the Delivery Point the quantities of gas (up to the applicable MDQ / up to the agreed MaxHQ) Properly Nominated for delivery by the Buyer.

In respect of each day during the Take or Pay period, the Buyer will take the quantities of gas so made available for delivery by the Seller at the Delivery Point.

The Buyer usually has the rights to request changes to its nomination programs.

For example, if it relates to a Weekly Program, if the Buyer notifies the Seller less than [one week] prior to the relevant week, or if it relates to a Daily Program if the Buyer notifies the Seller less than [14 hours] prior to the relevant day, then the Seller shall be obliged to use reasonable endeavours (namely only this level of obligation) to comply fully with the variation so requested. It is also specifically agreed that the Seller's failure to comply with the variation so requested shall not constitute Shortfall Gas.

Those GSPAs that have Excess Gas provisions, will also state that Buyers may at any time nominate additional volumes of up to [**] MMBTU above the applicable MaxHQ ("Excess Gas") and Sellers shall make reasonable endeavours to comply with such nomination of additional volumes.

Minimum Nomination, Zero Nomination

Gas field production equipment does not always work well at very low levels. It is therefore customary in a natural gas sales agreement for there to be a minimum quantity that the Buyer can nominate for delivery on any day, and no less than this.

Although most GSPAs allow the Buyer to nominate zero, it will not be allowed to nominate quantities between zero and the minimum nomination level, as technically, Sellers' facilities would not be able to cope with this.

Minimum Nomination means [x] MMBtu or such other quantity of gas as may be established by the Seller from time to time during the term of the GSPA, as

the minimum daily flow of gas through the Seller's facilities and the pipeline, for the purposes of the proper operation of the Seller's facilities.

Zero Nomination – When Buyer literally nominates to receive no gas on a particular hour. Such a nomination usually requires Buyer to give Seller a notice of not less than [7] days.

Indeed, since gas field production equipment doesn't always work well at very low levels, it is customary for the Buyer to nominate a minimum quantity on any day. This can be set either as a percentage of the DCQ or as a fixed daily production rate.

The Minimum Nomination is the difference between the DCQ and Swing which a Buyer can nominate for delivery.

Thus, the minimum aggregate of all nominations is often either zero or greater than x [e.g. greater than 50 mmscfd]. The Seller, however, can be asked to use reasonable endeavours to deliver at rates less than the minimum agreed [i.e. less than 50 mmscfd if that is the volume agreed]. The actual minimal nomination volume that the Buyer can make will be set during GSPA negotiations based on the Seller's facilities and its other clients' demands.

Buyer is entitled to nominate every Hour, a quantity of Specification Gas between zero (0) and the MaxHQ, provided, however, that the Buyer will not nominate for any hour a quantity of gas that is less than its pro-rata share of the Technical MinHQ.

This share is to be calculated based on the ratio between the ACQ in the agreement and the cumulative annual contract quantities in all the gas sales agreements of the Seller pursuant to which the Seller will be delivering natural gas from the reservoir at such date.

Seller's obligation to deliver gas is the quantity of gas nominated by the Buyer, so long as that nomination lies between the minimum nomination level and delivery capacity.

Delivery tolerance

There is often also a delivery tolerance in the range of +/- 2% in a day and +/- 1% in a month.

Operational tolerance and TOP are not related. TOP should be a firm financial obligation, not related to the agreed 1%-2% operational tolerance. Sellers need operational tolerance in their attempts to meet Buyers' daily nominations.

If the Seller fails on any day to make available the Properly Nominated Gas (beyond the agreed upon tolerance) other than because of Force Majeure or because of scheduled maintenance, then this same quantity of natural gas will become part of an "aggregated shortfall quantity", which the Buyer can take at the beginning of the following month at the agreed upon discounted Shortfall Gas Price, prior to taking any other gas at the (higher) contracted Gas Price.

Seller's nomination

As stated above, nomination is usually made by the Buyer. However, there are also instances of Seller's nomination in a gas sales agreement. In such a case, the Seller nominates the amount of gas it expects to deliver, in a range around the estimated daily contract quantity. The Buyer is obliged to Take or Pay for the nominated quantity on a daily basis.

Namely, under a Seller's nomination, the wording in the GSPA would be on the lines of:

In respect of each Day of the Front Month, the Seller will make available for delivery and the Buyer will take delivery of the applicable Proper Nomination.

Under these circumstances, there is no right for the Buyer to nominate anything less than the volumes the Seller has stipulated in their 'Proper Nomination' and the Buyer will have to adjust its operations at its facility (e.g. if its facility is an LNG liquefaction plant) to whatever volumes of gas Seller sees fit to nominate day by day.

Some contracts have a "must take" obligation on the Buyer. For example, a Seller's Nomination type of GSPA for gas from an associated gas fields (i.e. fields with both natural gas and oil) where the Buyer's failure to take gas prevents lifting of more valuable liquids. Indeed, associated gas will often be sold as "sellers' nomination" gas, and in traditional gas markets such gas would command a lower price than Non-associated Gas. However, even under these circumstances this is difficult to enforce.

Case: Why would a Buyer accept a Seller's Nomination regime

A Buyer would most probably only agree to accept a GSPA with a Seller's Nomination regime, if the Buyer receives a very low gas price, to compensate for its lack of flexibility (namely Buyer has to take any volume of gas nominated by Seller).

Thus, although a priori, some Sellers may be tempted to force their Buyers (especially if this is an LNG facility with higher nameplate capacity than the gas volumes under negotiation), to take whatever the Sellers nominates, the flip side of this for the Sellers, is that this almost inevitably means Sellers will achieve a lower gas price under this approach, compared to a GSPA with a regular Buyer's nomination, because of the disadvantages of the Sellers' nomination inflexibility for the Buyer.

In addition, a Seller's nomination could provide a potentially worse Take or Pay regime for Buyers, and it could require Sellers to have to commit to pre-invest to provide extra capacity to the Buyer from the outset, when certain Sellers are not in a position to do this (due to lack of funding, unsuitable development plans, gas requirements needed to be available to another client to ensure higher ROI, etc.).

Furthermore, before embarking on such an option which may seem, a priori, advantageous to the Seller, there may be other, better value outcomes to consider over time.

Case: Example of a case of disadvantage of the Seller's nomination

In gas negotiations between a gas field operator and an LNG facility, the parties had originally agreed on a 100% TOP, with a DCQ of 500 mmscf/day. The parties then discussed an option of increasing the sale's volume to a DCQ of 1 bcf/day.

There were two possible options in this case:

Option 1 - Buyer's nomination - suggests signing two different agreements with two separate DCQ volumes: the first at 500 mmscf/day with a 100% TOP and the second with a DCQ of 500 mmscf/day, on certain pre-agreed terms and timing with the Buyer.

Option 2 - Seller's nomination - the Buyer and the Seller sign one contract with a total volume of 1 bcf/day, based on a Seller's nomination. The Seller's nomination was planned to be an 'average' of 800 mmscf/day.

From the Buyer's perspective, the new terms are effectively 100% TOP, which is the nature of the Sellers' nomination agreements.

Under option 1 (Buyer's nomination scenario), it would probably have been possible for the Seller to get the Buyer to agree to 100% TOP on the second DCQ as well as on the first tranche, i.e. 100% TOP on 1 bcf/day.

Under option 2 (Seller's nomination scenario), the Seller ends up only effectively receiving a TOP delivery of 80% (an 'average' obligation by Buyer of 800 mmscf/day based on the maximum 1 bcf/day), whilst the Buyer is burdened with a 100% TOP commitment. Thus, for the Buyer this is not only a 100% TOP obligation but one which in fact the Buyer may not even be able to manage to take an average take level of 800 mmscf/day.

This could occur, for example, if Seller 'bids' only 700 mmscf/d for half of a year and then expects the Buyer to take at the rate of 900 mmscf/d for the remaining half of the year (to reach the 800 mmscf/d average envisaged in option 2).

The Buyer may find this extremely difficult to accommodate, as it would mean running the LNG plant at a continuous 90% capacity for the whole of the remainder of the year which might be very onerous on the Buyer. Buyer would thus expect to have some cap on the extent of any increase in supply within a period of a year and this would reduce the level of the 'Proper Nomination' they have to accept. This will reduce further the effective level of TOP in the GSPA.

In the best of cases, under the Seller's nomination, Seller only gets 80% TOP compared to a possible 100% on the Buyer's nomination scenario. In the worst of cases, the Seller nominates different volumes at different times, making it too difficult for the Buyer to manoeuvre and thus possibly demanding even a reduction of the level of proper nomination the Buyer has to accept, which could reduce the TOP even further. Under such a condition, one would argue that Seller is disadvantaged by the new structure compared with a more conventional approach.

In addition, under the Seller's nomination option, with the extra capacity that is being 'firmly' provided by Seller (taking into consideration that these volumes are now considerable), the Buyer will probably want some demonstration of the ability of Seller to 'bid' up to the full 1 bcf/d, otherwise there is little real value to Buyer if they cannot depend on it and plan to use it. Therefore, the Seller will be unable to free up this additional 500 mmscf/d for other customers even if there is one offering better terms than the first Buyer.

Under the '2 DCQ' structure, Seller could hold back this additional volume until it explores what other market options are available to it. Seller could then make a reasonable decision about the best sales outlet for the gas at any particular time.

The second option of the greater volume of gas provided under the Seller's nomination may appear a priori to be attractive to an eager Seller. However, this approach however may effectively be committing the Seller to make extra sales available to Buyer without exploring the alternatives. It might be thus preferential for the Seller to keep the Buyer interested in the additional volumes but without commitment at the initial phase. This could be important if the Seller is exporting this gas to another country and may provide it extra time to examine its host country's export limits and obtain the necessary permits.

Bid – Put options

Bid/Ask, Put/Call options normally have a price spread attached to them which reflect a discount to market for the Seller's ability to Bid or Put and a premium to market for the Buyer's right to Ask or Call.

This kind of structure makes sense if it includes an element of price spread (higher or lower) built into it for the additional volumes. Otherwise, it just becomes a one-sided Seller's nomination structure.

4.6 Assignment

An assignment occurs when one party hands off the contract's obligations and benefits to another party. Normally, a GSPA will make a provision, that "neither Party may assign, charge, pledge, encumber or otherwise dispose of the Agreement or any of its respective rights and obligations hereunder or thereunder without the express prior written consent of the other Party".

If the Parties agree to detail the assignment, the assigned Party should be as creditworthy as the party farming-out.

Such a clause can cause problems if all the rights are not assigned.

Example: A major oil and gas company was negotiating buying gas from another country for re-export, but wanted to include in the GSPA the ability

to assign part of the contract and volumes to the host import country in case such country made a demand to have gas for local consumption

If through assignment there are then two different Buyers (such as the major IOC as well as the state NOC in the same country), this pattern complicates matters, as each Buyer makes separate nominations.

Even if the NOC makes such a demand on the IOC, it would be better to maintain a single nomination done by one Buyer. This would ensure that the Seller does not have to get involved in allocation disputes between the two Buyers, as to which party received which volume of gas on any given day.

If for political or other reasons it becomes necessary to split the contract between two Buyers, it would be better to include a clause that states: 'If Assignment by the Buyer results in more than one Buyer under the Agreement then the Buyers shall appoint a Buyers' Representative to act on behalf of all Buyers on operational aspects of the Agreement and in particular to provide a single nomination.'

4.7 Liability

The Buyer's liability is limited to pay for the TOP quantity. The Seller's liability is limited to supply Shortfall Gas at the Shortfall Gas Price.

However, as stated previously, although difficult to enforce, some contracts have a 'must take' obligation on the Buyer (e.g. Seller's nomination type GSPA for gas from associated gas fields where failure to take gas prevents lifting of more valuable liquids).

It is usually acceptable that Sellers have limited liability if they cause damage to the Buyers for having supplied off-spec gas. However, one would expect a Buyer to have the right to refuse off-spec gas once it has noticed something is wrong or continue to take the gas if it desires to do so, at some discounted price.

Before the point of the Buyer realizing it is receiving and taking off-spec gas, the Sellers' have a liability vis-à-vis the Buyers. Such liability is normally limited to the cost of repair, replacement, etc. to Buyers' facilities and any third-party liability Buyers have incurred by passing the off-spec gas further downstream.

4.8 Conditions Precedent

All GSPAs have Conditions Precedent (CPs) that need to be resolved before a contract becomes unconditional, especially inter-state GSPAs. A GSPA does not become unconditional and effective until all the CPs have been satisfied, so it is important that both sides to the GSPA understand the CPs and when they become unconditional. Each side must understand when each particular CP needs to become satisfied. Namely, even if a contract is sealed and signed, as long as the CPs have not been met and fulfilled, there is no guarantee that the contract will be realized.

In drafting the GSPA, the parties need to ensure that the last possible date of the contract becoming unconditional, is in line with other dates that parties are committed to externally to the GSPA, such as their gas field's lease, regulatory milestones or otherwise.

If one party asks for too long CPs or CPs which are too easy to manipulate it could mean that said party is using the negotiations as a 'stalking horse' to get a deal elsewhere. Nevertheless, some CPs might indeed take a considerable amount of time to be resolved, especially if they relate to international deals. International oil and gas companies move extremely slowly, especially in complex international transactions, and some the CPs could take even up to 1-2 years to be resolved (this is acceptable practice), without this being regarded as too long (namely this would not necessarily constitute a case of one party using the other party as a stalking horse).

On the other hand, If Sellers in export country (e.g. owners of a large gas field that are keen to sign an anchor Buyer) demand too short a time for the Buyer in import country to be able to satisfy its CPs, then Buyer may not even attempt to meet the deadline, if for example it knows it will lose face in its own host country if seen to try and fail.

Case: Is the Seller in a complex international GSPA in a better position if:

- a) Seller signs the GSPA with extensive CPs that may not be satisfied until after an extensive period, if at all. Or
- b) Seller leaves the GSPA 'on the table' unsigned until more progress has been made on some of the CP issues.

The Buyer demanded long CPs that would take up to 2 years to resolve, which somewhat daunted the Sellers that were eager to finalize a contract with an

anchor Buyer to reach FID on the development of their field. The Sellers thus put pressure on the Buyer to have much shorter CPs, in the range of 6 months.

On the one hand, under such circumstances, there is the risk that although the Buyer will agree to Sellers request and sign the GSPA with the shorter CPs, this leads to the probability that Buyer will simply 'walk away' at the expiry of the first time-limit, with CPs thus unresolved and no GSPA signed. Indeed, the Buyer may sign such a GSPA despite this seeming "pressure" on it, in order to take advantage of the short-time frame to put its own pressure on its host government to revise its terms for production and sales of new gas in country or to buy gas from another supplier. Namely, under such circumstances, the Seller in the exporting country is just used as a stalking horse, but Buyer in the importing country still walks away from the GSPA once the first unmet CP is encountered. The Buyer prefers to play along with the Sellers, rather than simply not signing the GSPA, because it has the benefit of the 6 months to improve its other options at no cost to itself.

Compared with this option, leaving the contract unsigned while progressing the CP issues, or signing the GSPA with extensive CPs, amounts to more or less the same outcome (i.e. the Sellers receives no effective commitment from Buyer).

Signing the GSPA but with a reasonable period for CP satisfaction – possibly 12 months, may give Buyer the period it needs to satisfy the issues. In addition, although this longer period (namely, longer than the 6 months the Sellers were demanding) may a priori seem unsatisfactory to eager Sellers and they may try to pressure the Buyer to shorten the period to satisfy the CPs (with the potential above mentioned negative outcome), a signed GSPA with nevertheless a long CP period can also be to the Seller's advantage (compared to postponing the signature thereof). It enables Sellers to announce the execution of a signed GSPA, raising confidence levels for purposes of fund-raising and negotiations with equipment suppliers, with potential clients and with Sellers' own host government. Indeed, most of the attention (media, public, government, etc.) is often focused on the announcement of the GSPA execution, not on the details of the CPs and whether they will be satisfied, and when.

However, under the above circumstances, it is important for these Sellers that need an anchor Buyer to continue to explore other possible sales for their gas under either of these scenarios as there is no guarantee until the CPs have become unconditional that Buyer will commit to the GSPA and there is no realistic way of forcing them to do so.

Exclusive negotiations

Buyers might demand that Sellers be precluded from entering into Third Party Negotiations to supply gas to another Buyer in the same host country during the CP period, and this is a legitimate request which the Sellers should acquiesce to. The Sellers, however, should not agree not to carry out negotiations with other potential Buyers in other countries for this same tranche of gas during this period.

In addition, once the GSPA becomes unconditional, the contract should not have any restrictions imposed on Sellers to sell gas to any other Buyers in any country, including in Buyers' country, subject of course to the regular 'no overselling' restriction in the GSPA, imposed on Sellers.

As long as the contract has not been signed, in fact as long as the CPs have not been made unconditional, then clauses within the contract can be renegotiated. One can even go further and say that parties can always ask for and agree amended terms even during the life of the GSPA after it has been executed. The question is, what would the party seeking such amendments have to pay/concede to get them. In any case, it is clear that this is horse-trading - contracts are typically negotiated as a whole, with horse-trading over pricing and non-pricing clauses.

4.9 Force Majeure

Force Majeure (FM) literally means "greater force". FM clauses in contracts excuse a party from liability if some unforeseen event beyond the control of that party prevents it from performing its obligations under the contract.

Invocation of a FM, excuses non-performance and suspends performance under a contract where the failure to perform is due to circumstances out of the control of the defaulting party. The FM clause could be worded as follows:

In natural gas contracts, The expression "**Force Majeure**" means any event or circumstance that is beyond the reasonable control of the Party claiming Force Majeure (acting and having acted as a Reasonable and Prudent Operator) resulting in or causing the failure of a Party to perform any one or more of its respective obligations under their Agreement, which failure could not have been prevented or overcome by the exercise by such Party of the standard of a Reasonable and Prudent Operator, including without limitation: war (declared or undeclared), military action, acts of terrorism, fire, storm, lightning, earthquakes, subsidence; acts or omissions of the government; breakage, or malfunction of,

or accidents to machinery, pipelines or facilities; failure of the Transporter to perform due to a force majeure event under the Gas Transportation Agreement (GTA); failure of gas supply due to well non-performance or failure, inability of Sellers to maintain deliverability, reservoir non-performance, blowouts, or any event which is beyond the Sellers' control acting as a Reasonable and Prudent Operator, that causes or results in a material reduction in the quantity or pressure of gas in Sellers' Reservoir.

For the avoidance of doubt, it is hereby clarified that the following events and circumstances shall not constitute a Force Majeure: changes in market conditions, including changes that directly or indirectly affect the demand for or price of gas, electricity or any other products manufactured or produced by the Buyers or the Sellers, including inter alia, loss of customers.

If a GSPA is a Supply Contract, then the Seller should not be able to claim reserves' failure as FM. Under a Supply Contract, a Buyer is not agreeing to take the 'reserves risk' as it would under a Depletion Contract. This is especially the case, if the GSPA stipulates that the Seller is in fact seeking the 'right to supply from any other sources of gas'. Thus, Seller should not be able to claim for FM relief due to the reserves' failure of any particular field.

For an FM clause to bite, it must be the delivery of the gas which must be impossible. Thus, if the contract is silent as to the origin of the gas, the supplier should source the gas from another field, even another region if in principle possible.

Thus, when negotiating a GSPA for a Supply Contract, the Buyer needs to ensure that all the suppliers (if there are as is usually the case a consortium of gas suppliers) can indeed supply the agreed volumes in the GSPA from another source of gas, namely that they all have another field to supply from. If not, the party in the consortium of gas suppliers that does not have another field should reach an agreement with those within its consortium that do have another field, to ensure that each party can fulfil its part of the GSPA from another field at no risk, so they can keep up with their partners who have other sources.

At the end of the day, however, FM can include anything that the parties agree to at the time of the negotiations and the writing of the GSPA document. In negotiating FM clauses, the parties in fact have to try to anticipate the unpredictable. Although the phrasing of FM clauses can often include template-like wording, it is also

necessary to contemplate the specific contract being negotiated and include relevant references to the issues in question.

In addition, deletions of certain FM articles in subsequent GSPA drafts throughout the negotiation's process, may appear under the form of a new clause called "Exclusions to FM relief". If such a clause is introduced by one party, the other side has to pay attention and realize that this is in fact a "double negative". It in fact means that the new item has now become a Force Majeure and needs to be carefully studied by the other party as why it was introduced belatedly.

It is also important for each party to understand its potential exposure up and down the chain, all based on the level of risk they are comfortable with. The risks also differ from region to region. Unforeseen events are not easy to predict or define and thus Force Majeure clauses continue to be an active source of disputes. Since FM is effectively a 'contractual exceptions' mechanism, it will often be construed against the party seeking to rely on it²⁵.

The risks also differ of course depending on whether one is the Buyer or the Seller and the level of investment necessary to make for a particular transaction. Thus, if the owner of a gas field has to spend billions of dollars to develop its field, in order to sell gas into an existing LNG facility, or to a state utility electricity provider, such a Seller needs to be more meticulous about the "rights" given to the Buyer under its FM clause, which could enable Buyer to walk away from the GSPA, potentially well-before Seller has even recuperated its expenses. Such a Buyer may be less exposed to risks.

Identifying the potential sources of disruption and providing for the consequences, cognizant of the relevant laws, can prevent exposures and lead to a quick resolution of a non-performance issue. Regular evaluation and re-evaluation of FM regimes is recommended.²⁶

Usually, GSPAs include a termination clause for prolonged events of FM, which is open to either Buyer or Seller after an agreed period. Parties could agree that such a prolonged event can be 24 months. This extended FM could for example consist of this period being characterized as one "during which less than 50% of the ACQ has either failed to be supplied by the Seller or taken by the Buyer."

Occurrence of Force Majeure will generally suspend the obligations of the Party affected by the event. With the invocation of FM, parties will be discharged from all

²⁵ <https://www.reedsmith.com/en/perspectives/2018/02/force-majeure>

²⁶ Ibid

future obligations and liabilities arising from the contract. Parties can then 'walk away' without any compensation being paid for the loss of future obligations. However, under termination of the GSPA for extended FM by either party, because the contract was terminated through no fault of any party, under normal circumstances, the Sellers would pay back to the Buyers any cash-out of Make-Up aggregate and Shortfall Gas and the Buyers would have to pay for any benefits received for part-performance.

Notwithstanding that an event of Force Majeure otherwise exists and has occurred, the provisions of the contract should not excuse:

- The failure of a Party to make any payment of money when due in accordance with either parties' obligations under their Agreement;
- Failures or delays in performance resulting from financial hardship or the inability of a party to make a profit or receive a satisfactory rate of return;
- In the case of the Sellers, failure or delays in performance resulting from insufficient Proven Reserves in their gas field (other than in circumstances of unexpected naturally arising events);
- Failure or delays in performance resulting from changes in market conditions or loss of customers or market share.

Notification of an event of FM

If an FM event has occurred, the party affected should promptly inform the other party. The relevant clause could be worded in the following way:

Promptly upon the occurrence of an event that may subsequently lead to a claim for relief under the FM clause, and in any event not later than x Business Days [e.g. 5] after the date on which the affected party becomes aware of such occurrence, the party affected shall give written notice of such event to the other party, describing such event and the obligations, performance of which could reasonably be expected to be delayed or prevented thereby. In the event any party claims relief by reason of Force Majeure, it shall promptly notify the other party thereof and shall state in such notice the particulars of the event of Force Majeure giving rise to such claim, in as much detail as is then reasonably available including the place and time such event occurred.

During the period of Force Majeure, the party affected by an event of Force Majeure shall, at the request of the other party, give or procure access (at the

expense and risk of the party seeking access and subject to such reasonable conditions in relation to safety, security and confidentiality as the owner or operator of the relevant facility may impose) at all reasonable times for a reasonable number of representatives of such party to investigate the circumstances of such event of Force Majeure.

During the occurrence of an event of Force Majeure and prior to resumption of normal performance, the parties shall continue to perform their obligations under the Agreement to the extent not prevented by such event of Force Majeure.

Remedial steps

As soon as practicable after the occurrence of an event of Force Majeure, the party claiming relief shall take all reasonable steps in the applicable circumstances to remedy the failure, inability or occurrence; and use reasonable endeavours to procure that the operator of any relevant facility shall take all measures that are reasonable [excluding, in the case of the Sellers, sourcing gas from sources other than the gas field if it is only a Supply Contract] in the circumstances, in order to resume normal performance of the Agreement, [including pursuing diligently any insurance claims which may be capable of being pursued], provided that such party shall not be obliged to make more than commercially reasonable expenditures.

Allocation of gas supplies in events of FM

Even in events of FM, and/or other events, the ability by the Seller to provide gas may not be completely impeded and may be only curtailed. Thus, it is important for Buyers to negotiate during the GSPA talks, allocation priority so that if certain volumes of gas can be provided by Seller, that Buyer gets the best deal possible.

The priority should be something on the lines of: firm sales before interruptible sales, domestic sales before export sales. Thus, for example, such a clause could include the following wording:

If, due to Force Majeure, the Sellers' ability to make available Properly Nominated quantities of gas is impaired, then the Sellers shall first curtail all interruptible sales of gas from field x before curtailing any firm sales of gas (which firm sales include sales under the Agreement); and second, curtail firm export sales of gas prior to curtailing firm domestic sales (including firm sales under the Agreement).

A firm contract provides power plant operators with an agreed-upon capacity for the producer or pipeline to supply natural gas, establishing a high priority for fuel requested by the power plant. The supply or delivery of natural gas cannot be curtailed under a firm contract except under unforeseeable circumstances.

In contrast, interruptible contracts (also called non-firm contracts) are lower-priority fuel supply and transportation arrangements. Under these contracts, the flow of natural gas to a power plant (or to another facility) may be stopped or curtailed if firm contract holders use the available capacity, or if other interruptible customers outbid the power plant. These contracts are generally set up for short periods, often for next-day delivery. Gas prices in interruptible contracts are usually less expensive than firm contracts, reflecting the higher risk to Buyer of disrupted fuel receipts.

If the GSPA is an international transaction between a Seller in country 'A' and a Buyer in country 'B', the Buyer will at least want to negotiate that it has the same priority rights on any gas that may remain to other import Buyers. Under such conditions, the Buyer may wish to include a clause that states that "the Seller may curtail firm export sales of gas from its field, provided that firm export sales of gas under the Agreement shall be curtailed in the proportion that the applicable DCQ under the Agreement bears to the maximum daily delivery quantity under the Seller's other arrangements for firm export sales of gas from its field".

A Buyer importing gas from another country, will most probably have lower priority rights than any Buyer in Seller's host country, regardless of what may be worded in the GSPA or whether the contracts are firm / not firm. Indeed, if there is a sudden shortage of gas in Seller's host country, the regulators may very well have put in place regulations requiring local needs to be satisfied first. Buyers need to thus examine Seller's legislation and/or negotiate a government-to-government agreement, ensuring that exports will not be curtailed, or in the very least understand the implications of such curtailment.

Case: Allocation of gas supplies - priority given for remaining gas to certain Buyers

If an event of FM occurs, or any other failure of supplying gas by Seller, the anchor Buyer might demand to get first allocation of whatever gas remains available, rather than pro-rata allocation of gas available by the Seller.

Other Buyers thus need to examine what other commitments its gas supplier has committed to (or may commit to in the future) to safeguard its ability to at

least receive pro-rata allocation and not be pushed down the order of priority, if another Buyer has (or in the future may) achieved “first allocation rights” for itself.

Whatever the case, the Seller should demand reciprocity, namely that it receive in the very least a pro-rata reduction across all of the Buyer’s supplies into the Buyer’s facility (e.g. an LNG plant) in the event of FM reduction of gas offtake by the Buyer.

Case: General definition of FM to be aligned with other projects

If one of the parties asks to have a definition inserted under FM that declares that “the general definition of FM is to be aligned with their other projects, except where deviation is clearly required”, should the counter-party accept this?

Answer: The other party must make sure that it is allowed to see the FM clauses in said other projects. In addition, it needs to realize that there is a danger of the 1st party taking this out of context and transferring the FM clauses to another agreement.

Extension of the agreement for FM

It is normal to extend the term of the contract if during the term an event of FM has occurred. Such a clause could be worded in the following fashion:

All dates and periods referred to in the Contract shall be deferred or extended as the case may be.

Or in greater detail:

Subject to the rights of termination, on the occurrence of a Force Majeure event, then the date referred in clause x, shall be deemed to be automatically deferred by the number of Days equal to the aggregate quantity of gas not delivered (due to such Force Majeure event) divided by the applicable DCQ (rounded to the nearest whole number); provided that no such deferral will have the effect to extend the Term beyond the term of the Seller’s Gas Leases (if a Supply Contract) or in violation of any applicable Law.”

Extension of the term of the contract for lesser reasons than FM, such as Political Risk, are to be negotiated between the Buyer and Seller. This is because the Seller may not want to extend the term of the contract, as it may wish to be able to negotiate other sales without the restrictions of a possible non-FM extension sometime down the line, hovering over it. If Seller feels compelled to agree to an extension of the term of the GSPA for reasons that are not FM, it in any case, should try to negotiate not having to provide more than a 1-year contract term extension for non-FM reasons.

4.10 Political Risk

Sometimes a Buyer may also try to reduce its TOP obligation, for reasons that are not FM. This could include certain circumstances of political risk, or gas diversions caused by Buyer's host state. The Seller should try to resist these as much as possible.

Case: Political risk events and Make-Up Gas

The Buyer in country 'A' is buying gas from the Seller in country 'B'. The two countries have complex political relations. The Buyer is thus concerned that an event, which it defines as a "political risk event" sometime in the future may cause its host government to prejudice gas supplies from exporting country 'A'.

If "political risk events" are included in an inter-state GSPA, it is in order to differentiate such events from Force Majeure, and to provide a different (lesser) degree of protection to the party 'in fault'.

In the case under discussion, the Buyer in country 'A' may try to negotiate the right for a lower TOP and a quicker ability to MUG in the case of political risk in the country in which it operates. In one GSPA in which the author of this document was involved, the Buyer even asked to be able to take its 'political risk MUG' after the next month rather than on an annual basis.

The Seller needs to understand that under such a condition, that it would effectively have to maintain two sets of TOP accounts: one for 'normal' annual TOP, where recovery of Make-Up Gas occurs after the end of the year, and a second for 'Political Risk' TOP, where recovery of Make-Up Gas can now occur as soon as the next month.

Before agreeing to this, the Seller needs to carry-out a financial modelling on the way this might work and the damage to cash flow that might be caused to it.

Such a situation could lead to having both forms of Make-Up recovery working simultaneously in some years.

If during negotiations, the Buyer asks for such a benefit, the Seller might be willing to accept some of these more onerous terms, but probably only if Seller is looking for reciprocity on the same areas of political risk from its own host country (e.g. Seller's host country refusing in the future to allow exports of gas to Buyer's country, not for reasons of FM or gas shortage but for what would be described as political risk reasons).

If political risk events are included in a GSPA, then a worthwhile exercise would be for each side to prepare a matrix of those clauses that constitute Force Majeure and those that constitute Political Risk, as defined in their GSPA. This would help parties to get a clearer picture of what event would be protected by FM and what would fall under Political Risk.

An example of such a matrix can be seen below.

Political Risk vs. Force Majeure Matrix

Below are some clauses which would often fall under FM (green blocks), whilst others may not have this 'protection', but could be included as political risk events if the parties agreed to this in their contract

Risks	To Buyer	To Seller
Fire explosion, acts of God including flood, lightning, storm, typhoon, hurricane, tornado, earthquake, soil erosion		
Any war that results in business interruptions not due to government acts		
War involving Import Country , invasion, or armed conflict that result in government acts		
War involving Export Country , invasion or armed conflict that result in government acts		
War between two countries other than Import & Export countries that results in Export government acts		

Risks	To Buyer	To Seller
War between two countries other than Import & Export countries that results in Import government acts		
War between Import & Export countries that results in government acts; Civil war, revolution, military uprising, acts of public enemies that result in business interruptions not due to government acts		
Civil war, revolution, military uprising, acts of public enemies in Import country that results in government acts		
Civil war, revolution, military uprising, acts of public enemies in Import country that results in government acts		
Terrorism		
Embargo, blockade, strike, lockout, industrial disturbance		
Acts, laws, rules, regulations and/or orders of whatsoever nature of Export Government Authority other than set out in this Matrix		
Acts, laws, rules, regulations and/or orders of whatsoever nature of Import Government Authority other than set out in this Matrix		
Acts, laws, rules, regulations and/or orders of whatsoever nature of the EU, including the European Commission and any competent Antitrust Authority; and/or the United Nations and any instrumentality thereof; and/or NATO		

For the avoidance of doubt this matrix is not an attempt to define Force Majeure or Political Risk, it is indicative and non-exhaustive



No Force Majeure Protection



Force Majeure Protection

4.11 GSPA termination clauses

A GSPA usually terminates either when the Total Contract Quantity (TCQ) has been delivered or when the agreement reaches its end of term. Usually, it is stated that it is the earlier of the two.

Long term GSPAs do not typically have 'get out' clauses that make it easy for either party to leave the contract before the end of the term / receipt of all the TCQ.

Indeed, termination clauses are rare and would be inappropriate for greenfield projects that need to finance loan repayments over 20 or 30 years. However, they do sometimes have a 'hardship' clause to enable renegotiations or a 'price reopener' clause which can achieve the same ends.

The majority of contemporary gas contracts contain detailed provisions, however, for early termination by one party in certain events, such as extended Force Majeure and failure by one party to fulfil its obligations to the other, in particular if a party fails to make timely payments. In the case of extended Force Majeure, where the obligations of the affected party are suspended during the period of FM, either party can terminate the contract before the end of the term. The wording of such a clause could be as follows:

If by reason of an event of Force Majeure any party ("Affected Party") is unable to perform any material obligation required to be performed under the Agreement and such inability to perform continues for a period [e.g. 270 consecutive days] from the date of commencement of the Force Majeure event, the other party that has not invoked the Force Majeure may terminate the Agreement by giving [e.g. 90 Days] prior written notice to the Affected Party and, upon the expiration of such notice period, the Agreement will terminate without prejudice to any rights of the parties that have accrued prior to such date, except if, before the specified termination date such Force Majeure event and such inability has ended.

Or

Should an event of Force Majeure prevent delivery or taking of [e.g. 50% or more] of the Annual Contract Quantity for a period of more than [e.g. 24 Months] after receipt of the relevant notice, then either the affected party or the non-affected party shall have the right to terminate the Agreement by notice in writing to the other party. Following delivery of such notification, no party shall have any

claims against, or liability to, the other, save in respect of antecedent breaches under the Agreement.

Early termination would also ensue in case of bankruptcy, insolvency, effective dissolution, winding-up or liquidation of one party.

In wording the GSPA, each side needs to understand whether it, or the other side, is more likely to benefit in the future from the ability to cancel the GSPA (for the Buyer if it is able to buy much cheaper gas or for the Seller if it can find a substantially better value market), if the clauses are there for the taking. Thus, when drafting a GSPA, the parties must scrutinize the wording of all the termination clauses, if there are such, and beware of the pitfalls that they may be opening themselves up to if their counterparty will have the incentive down the line to terminate the contract.

Seller needs to pay attention to a potential problem, namely that if its Buyer does have the ability to walk away from the contract, in the event of a potential termination after a certain period, that during the interim period between announcement of said termination and actual termination, that Seller might not be able to book the income from TOP payments, nor will it be free to sell the locked-in gas to any other customer.

A simple termination clause will commonly consist of two basic elements: breach of contract and insolvency. Termination clauses are usually written on a mutual basis, in which case either side will be able to bring the contract to an end.

Early termination can also be invoked for failure of one party to carry out its obligations under the contract, with the affected party being the entity that can invoke early termination. Under these circumstances, the party which has failed to fulfil the contract terms must pay all outstanding obligations or liquidated damages to the other party.

If Sellers terminate a GSPA because of default by Buyers, then in many cases, Sellers are allowed to keep any unrecovered TOP payments and Shortfall Entitlement. However, although this is a logical outcome and is often the case, it is not universally so. Indeed, there are GSPAs where the sides may also decide to agree on a capped 'walkaway' provision, which defines maximum liability for either side that may be less than the accumulated TOP payments or Shortfall Entitlement.

There is also the question of whether, under English Law at least, the extent of these liabilities could represent a penalty and therefore be overruled in court. For example, if a Seller is able to retain all TOP payments but is then able to resell the

gas to another Buyer, this might well be construed by the courts as an unacceptable penalty imposed on Seller.

Although some GSPA contracts allow repayment of outstanding Make-Up Gas by the Seller to the Buyer after 'normal' termination (i.e. after expiry of the contract term), a Seller should try to resist agreeing to this during the negotiations. Indeed, any clause in a GSPA that seems to override other previous termination payments by requiring Seller to repay all outstanding Make-Up and Shortfall discounts to the Buyer following any termination other than a 'Default' or 'Force Majeure' type termination, should be rejected by the Seller if it has the power to do so during the negotiations of the drafting of the GSPA.

In addition, Seller should resist including in the GSPA termination clauses that have no consideration of the volume of gas involved. Namely, Buyer should not be able to invoke termination for the non-supply of unsubstantial volumes of gas.

Although termination clauses can vary and depend on the detailed terms, in principle, termination of a GSPA, like in any other contract, only happens when the GSPA says that it does and until that point parties are bound by the terms. Sometimes, even after termination, there are terms that apply to limit the parties' freedom of action. Such a clause could be worded as follows:

Termination or expiry of a GSPA shall be without prejudice to the rights and liabilities of the parties that have accrued prior to termination or expiry... and clauses [x, y, z] shall survive the expiry or termination of the contract.

Some of the common Buyer's termination events (namely events that entitle the Buyer to terminate the Agreement), could include:

- If the Seller fails to pay any sum which is due under the Agreement and such amount is not placed in escrow;
- If the Seller is unable to pay, suspends payment, or agrees to a moratorium with respect to all or a substantial part of its debts, makes a general assignment for the benefit of its creditors except to the extent otherwise permitted by the Agreement, takes any proceeding with a view to readjustment, rescheduling or deferral of all or a substantial part of its respective indebtedness (other than in the case of a refinancing), or any order is made for the winding up, liquidation, dissolution, or administration of a

Seller; all under any bankruptcy, insolvency, or similar laws applicable to such Seller;

- If the Seller fails to be ready to deliver gas at the Delivery Point (with possibly provisioned number of days to remedy such a failure) or if the aggregate quantities of gas made available for delivery by the Seller are less than some agreed percentage of the ACQ;
- If a Commercial Default occurs on more than x days [e.g. 10 days] in any one-year period;
- If the Lease and/or export license is terminated.

A termination clause for non-payment by one of the parties, can eventually lead to the termination of a contract if not remedied within a reasonable time frame. The wording of such a clause could be as follows:

In the event that one of the parties to the Agreement fails to timely make a payment that is required thereof according to the GSPA, the delinquent amount shall accrue interest at an annual rate equal to LIBOR interest plus 5%, from the payment due according to the Agreement until the date of actual payment. If the delinquency lasts x days [e.g. 10 days or more], the party entitled to the payment may, by giving prior written notice of x days [e.g. 21 days], suspend provisions or receipt of the gas, as the case may be. If the delinquency lasts x days [e.g. 120 days] from the relevant payment due date, the party entitled to the payment may, by given prior written notice of x days [e.g. 21 days], terminate the Agreement. Exercising the right to terminate the Agreement shall not constitute a waiver of other remedies that are available to such party.

It is agreed and understood by the Parties that any Buyer's Termination Event constitutes a repudiatory breach of the Agreement by the Seller.

Some of the common Seller's termination events (namely events that entitle the Seller to terminate the agreement) could include:

- If the Buyer fails to pay any sum which is due under the Agreement and such amount is not placed in escrow;
- If the Buyer's Parent Company Guarantee ceases to be in full force and effect, and the Buyer has failed to provide to the Seller satisfactory alternative credit support in respect of its obligations;

- If the Buyer or the provider of the Buyer's Parent Company Guarantee is unable to pay, suspends payment of, or agrees to a moratorium with respect to all or a substantial part of its debts, makes a general assignment or any composition with or for the benefit of its creditors except to the extent otherwise permitted by the Agreement, takes any proceeding with a view to readjustment, rescheduling or deferral of all or a substantial part of its indebtedness (other than in the case of a refinancing), or any order is made for the winding up, liquidation, dissolution, custodianship or administration of the Buyer;
- If the aggregate quantities of gas taken and paid for by the Buyer are less than some agreed percentage of the ACQ;
- If the Buyer fails to be ready to take gas at the Delivery Point (with possibly provisioned number of days to remedy such a failure).

It is agreed and understood by the Parties that any Seller' Termination Event constitutes a repudiatory breach of the Agreement by the Buyer.

Capped compensation in case of termination

Compensation for termination must in any case be capped, and any wording relating to 'compensation for deprivation of economic benefit' is difficult to quantify.

For example, if a GSPA contains a vague clause that states that "Buyer and Seller can claim compensation for deprivation of the economic benefit had the GSPA lasted full term", it can lead to excessive disputes between the parties.

Most long-term GSPA negotiations regarding termination, end up coming around to the issue of "what is a fair price for either side to terminate the agreement" and include capped damages in some way that do not bankrupt either party. This cost cannot be too low or one or other party could use it as a device to walk away from the contract, if circumstances warrant this. However, the cost has to be significantly less than the cost to Buyer or Seller being locked into maximum liability for the life of the GSPA.

Case: Should a GSPA include pre-defined termination amounts

Pre-defined termination payments have the advantage of the sum being known in advance by both parties and thus to reduce disputes on the issue later on.

On the other hand, the danger is that both sides then know the price for 'buying' their way out of the GSPA. This can make it easier to terminate as each side knows the alternative it needs to achieve to make it worthwhile (e.g. if Buyer can get access to lower cost gas in the future, it could easily calculate if it is worth its while to terminate the GSPA by paying the pre-defined payments, based on the alternative gas price available).

Thus, pre-defined termination amounts can be a self-fulfilling prophecy, unless the levels are set very high.

Parties need to pay attention also not to become over-cautious vis-à-vis the other side. Namely, clauses that include an automatic termination, such as after non-payment of money owed in a specific timeframe may be overzealous when not business critical and leniency in the matter could save a usually profitable relationship. It is thus advisable that the wording of a termination clause should allow for some discretion on whether to terminate.

Notification of termination

In the occurrence of any Termination Event, the terminating party may give notice thereof to the other party, specifying in reasonable detail the nature of such Termination Event. The wording of such a clause could be as follows:

At any time after the expiry of a period of [e.g. 60 Days] after the terminating party gave notice of a Termination Event, unless the circumstances constituting the Termination Event have been fully remedied or have ceased to apply, the terminating party may terminate the Agreement with immediate effect by giving notice of such termination to the other party.

Case: Termination for non-FM reasons – Obligation to make replacement sales (claw-back mechanism)

If the Buyer (e.g. an LNG facility) wants to include in the GSPA a termination clause (for non-FM reasons), which requires Buyer to compensate Seller to the tune of \$x [e.g. \$1.5 billion], but then adds a clause that states that if/once the Seller has found an alternative Buyer for this tranche of gas, then the Seller has to compensate the Buyer to the value of \$x [e.g. \$2/MMBtu], until 50% of the \$1.5 billion is repaid (Obligation to Make Replacement Sales).

Answer: This would be an unjustified demand by Buyer on the Seller and would diminish the value of the termination payments from the Buyer to the Seller.

If the Seller is nevertheless willing, or feels obliged, to provide some pay-back mechanism to the Buyer in case of the Buyer's termination once the Seller has achieved a replacement GSPA for that tranche of gas, then any compensation should be based on a % of the gas price, not a flat dollar denominated \$2/MMBtu.

Such a clause could be drafted in the following way:

Following termination of the Agreement pursuant to Clause x, upon the Seller selling or making available for delivery to Third Parties any additional quantities of gas over and above any contractually committed gas sales in existence prior to the date of termination of the Agreement (a Replacement Sale), the Seller shall pay to the Buyer a monthly payment (a Compensation Payment) calculated as the product of (i) the quantity of gas sold by way of any Replacement Sale during any month and (ii) [10%] of the prevailing gas price for that sale, until the earlier of 2 years or the time that the aggregate of Compensation Payments equals 50% of the amounts set out in Clause x [\$1.5 billion] accrued by the Buyer as at the date of termination.

If such a clause exists protecting the Buyer, then the Seller should ensure that the GSPA includes an equivalent claw-back mechanism in its favour, so that if Seller invokes a termination clause and has to pay compensation to the tune of \$1 billion* to the Buyer, then the Seller receives re-payment compensation from the Buyer if the Buyer sources alternative sources of gas.

Such a clause could be drafted in the following way:

Following termination of the Agreement pursuant to Clause x, upon the Buyer purchasing or taking delivery from Third Parties any additional quantities of gas over and above any contractually committed gas sales in existence prior to the date of termination of the Agreement (a Replacement Purchase), the Buyer shall pay to the Seller a monthly payment (a Compensation Payment) calculated as the product of (i) the quantity of Gas purchased by way of any Replacement Purchase during any Month and (ii) [10%] of the prevailing gas price for that purchase, until the earlier of 2 years or the time that the aggregate of Compensation Payments equals fifty percent (50%) of the amounts set out (\$1 billion) and accrued by the Seller as at the date of termination.

*The amount that the Buyer would have to repay [e.g. \$1 billion] vs. the amount that the Seller would have to pay [e.g. \$1.5 billion] differ, since Sellers are more exposed to the lack of revenue from Buyers than Buyers are from Sellers.

Case: Termination due to Political Risk Event

In international GSPAs signed between a Buyer and a Seller in two different countries, one side may attempt to try to get the other side to agree on terms for early termination for reasons of Political Risk events. Such events would be events that occur, which have not been classified as Force Majeure and are often events which would be activated by a combination of relatively low financial 'triggers' (e.g. an accumulated default by Buyer or Seller of a small sum such as \$500 million).

The concern is that the party that is most fearful that it may require the ability to terminate the contract (e.g. ordered to do so by its host country but for no apparent FM reason such as war), will want to include Political Risk termination events in the GSPA, in order to manipulate them at a later stage during the term of the contract, if and when required.

Although FM termination can also be manipulated, at least under FM clauses, there is the need to give the other party access to investigate the circumstances of FM and attest that they have indeed occurred which lessens this concern, whilst a mere Political Risk termination clause could be purely arbitrary.

As mentioned, if a party demands the ability to have Political Risk termination, it means that said party is indeed concerned that a political event in their host country might force them at some time in the future to have to terminate the contract. Although this could indeed be a legitimate concern, it could also just be a fall-back clause if potentially considerably lower cost gas were to become available to the Buyer in the future in its host country, or it could be a whim by a host government. Thus, the existence of such a clause will cause the Buyer to want to terminate the GSPA, if it has the option of doing so by the terms of the contract, because it is no longer commercially sound for him to continue to import gas or because its host government has ordered it to do so. Such a Buyer may seek "to engineer" a termination by using the easier Political Risk clause, if available, and if the 'penalty' it has to pay is lower than the commercial benefit it may gain from buying much lower priced gas, or going against the orders of its host country.

If possible, under such circumstances, the Seller should try to resist agreeing to the inclusion of such a clause. This may of course not always be possible, especially if there is a lack of parity during the negotiation in the power between the Buyer and the Seller, and if the Seller has less options to sell its gas, than the Buyer has to buy feedstock for its facility.

In fact, if the Buyer is a major O&G company seeking feedstock for a particular LNG liquefaction facility, Seller should be aware that it may well be competing not just on feedstock for this particular LNG facility, but that Buyer may at any time examine not only the options it has available to buy gas for this specific facility, but will also compare this to its options to buy gas worldwide for its different facilities. If the Buyer feels that it will have multiple options available to it in the future and demands to have the ability to terminate its contract, under such easier terms, then if the Seller insists on not allowing a Political Risk termination clause in the GSPA, the Buyer may walk away from signing the GSPA altogether.

Nevertheless, if Seller is developing a gas field at a considerable cost based on Buyer as a significant or even anchor client, then the Seller does need to receive a minimum reasonable protection from Buyer in terms of the other country's activities, so that whatever termination clauses are introduced into the GSPA (except and in addition to FM) would only occur after Seller has reached a certain threshold of revenues. Probably the minimum threshold that any Seller should agree to for non-FM termination, should be that Seller have recuperated the appropriate share of its CAPEX costs, but preferably even after it has recuperated potentially 1.5 times its CAPEX costs (R-Factor of 1.5). The higher rate is justified, as it may take considerable time for Seller to find an alternative Buyer, and Seller would be incurring both financial and operational expenses during the interim period, as well as loss of income.

Case: Termination ability for Political Interruption Events once the Buyer has accumulated a high level of Make-Up Aggregate.

The case below is one where the Buyer wants the ability to terminate the contract in case of a Political Risk Event and has set the trigger for its ability to terminate if it has accumulated a high level of Make-Up Aggregate [e.g. in excess of \$1 billion or has made monthly Periodic Payments in excess of \$1 billion in one year].

Although the Seller may not want to allow the Buyer to have any Political Interruption Events enabling him to terminate the GSPA (as explained above), it might be required to accept such a demand by Buyer. In such a case, setting the bar at a high level of MUG aggregate such as \$1 billion may be acceptable to Seller.

However, it is important that the Seller makes sure that there is not another - potentially contradictory clause - in the GSPA that might constitute a lower effective termination payment or claw-back clause [e.g. if the Buyer imposes a 'Replacements Sales' obligation on the Seller as in the example above].

In addition, the Seller must ensure that the [\$1 billion] value is sufficient termination payment (or the lower value if the Buyer has some kind of clawback clause) given the time it may take Seller to find other sales' outlets for gas and the ability for the Seller to service loan agreements and other financial obligations.

The ability of the Seller to accept such a termination clause, also depends on when the Buyer wishes such a termination clause to occur, within the term of the contract. If such a termination by Buyer occurs in the first [e.g. 5 years] of the GSPA, after Seller has just invested billions of dollars to develop its gas field and facilities, the compensation payment mentioned above would probably not suffice. The further out in time the termination occurs, the less damages it would cause the Seller.

If the GSPA terms also include low gas and oil prices for the initial and financially most important years of production and pay-back (because of market fundamentals during this period), then the problem of the termination would be compounded as cash returns are likely to be reduced. Under such circumstances, Seller should push for higher compensation levels for this type of termination.

If the Buyer does insist on such a clause, then it should be matched with the Seller having a similar right to terminate once its shortfall payments and other liabilities (i.e. including Commercial Default or any Buyer Stabilization payment requirements) have reached a certain sum, potentially at least [\$1 billion].

At the end of the day, there are few general rules, about termination by either side for whatever reason (and who has to pay what to the other party under different termination scenarios) – and it is all down to negotiations.

4.12 Tax stabilization clauses

Sometimes, one party will demand a stabilization clause from another party in case of taxes imposed on it by the other party's host country.

Buyer in country 'A' may try to word a clause such as:

The Seller would be required to compensate the Buyer and/or the Gas Transporter (if this was another entity that was constructing the pipeline to link the two countries) for any taxes introduced that cause Buyer additional costs. Such compensation is to be paid either as a lump sum or a reduction in the gas price.

The main concern in such a clause is that there is no cap on the liability demanded by the Seller. The GSPA might include a general de facto cap, if the Seller is able to terminate the GSPA and pay a certain fine for arbitrary or other termination. However, the Seller may prefer not to have to invoke termination, if it prefers to continue with the contract, and so it may want to introduce a cap on its liability within this specific clause itself, which does not require it to terminate the GSPA (or pay too high a fee in case stabilization is invoked).

In addition, the party that is asked to give such a stabilization commitment should ensure it gets the same protection from the other side, if relevant. It would only be relevant if party B (e.g. Seller) was also investing in party A's country (e.g. Buyer's country) and was thus prone to being taxed in the other country.

4.13 Destination clauses

International gas trade is dominated by contractual supply and offtake agreements that specify the duration and the size of the gas delivery and often come with destination clauses for LNG sales' contracts. Such destination restriction clauses confine the Buyer from reselling the LNG, outside of a designated geographic market (usually, the Buyer's home market).

Destination clauses restrict importers from reselling gas once purchased. Some contractual clauses prevent any diversion of cargoes to another destination or restrict the territories to which diversion can take place or the volumes that can be diverted. Destination-specific contracts mean LNG cargoes cannot be diverted en route to higher-priced markets but have to be reloaded at the originally agreed destination point.

A Seller may want to prevent a Buyer from being able to deliver cargoes to other destinations, because the Seller does not want the Buyer to compete with it in other markets or to compete with its other Buyers. A Seller may also be concerned about the costs of it having to deliver to alternate destinations and the potential disruption to its transportation logistics and schedule, or that delivery to a different market than the one designated in the contract may violate trade restrictions or the terms of the Seller's financing.

In contrast, a Buyer may view the right to deliver LNG cargoes to different destinations as essential to mitigating the Take or Pay risk created by its volume commitment (because it may not have sufficient customer demand in the designated delivery market to sell gas there at a profit) or to avoid a Take or Pay penalty. A Buyer may also have obligations to supply customers or its own facilities in different locations and it therefore may want to have the contractual right to deliver to multiple destinations. More generally, a Buyer may want destination flexibility to manage its overall portfolio (which may include different sources of supply with different pricing and other terms) and to pursue arbitrage opportunities.²⁷

Destination flexibility can also be implicitly restricted by a delivery ex-ship agreement (DES), which does not restrict the right to resell the gas but requires the gas to be first unloaded (i.e. regasified) and then reloaded (i.e. re-liquefied) before it can be sold to another Buyer, which is expensive. Not all regasification terminals have re-liquefaction and re-loading facilities. Only if the LNG is sold on a free-on-board (FOB) basis can the Buyer easily re-route the vessel to another destination.

Under an FOB contract, the Seller delivers when the goods are loaded into the ship. The title and risk relating to the cargo is transferred to the Buyer at that moment and the Buyer has to bear all costs and risks of loss or damage to the goods from that points.

Under a DES contract, the Seller delivers the contract goods when the goods are placed at the disposal of the Buyer on board at the named port of destination. In LNG trading, that would be when the LNG is delivered into a tank at the unloading terminal. The Seller has to bear all the costs and risks to the goods until that point.

²⁷ <https://globalarbitrationreview.com/chapter/1142624/destination-restrictions-and-diversion-provisions-in-lng-sale-and-purchase-agreements>

Destination clauses are under attack from various sides. After the European Commissioner found destination clauses incompatible with European competition law²⁸, Japan then also concluded that such clauses are anti-monopoly and has suggested that contracts should not contain resale restrictions.

The growing volume of US LNG, which is generally flexible and free from destination restrictions, can be a valuable bargaining chip in buyers' markets when consumers re-negotiate with their suppliers.

Destination flexibility seems to be on the rise.

4.14 Most Favoured Nation clause (MFN)

In GSPAs, it is important to maintain the commercial tension between Buyers and Sellers, throughout the lifespan of the contract. The contracts must thus be worded in such a way that they maintain this equilibrium throughout the term of the contract. In addition, they should not be dictated by regulators. In general, regulators err when they enable one side to have a unilateral right as this distorts the market forces and brings in too high a level of uncertainty making the upfront investments more complex.

Although there probably could be the opportunity to revisit GSPAs years after they have been signed and after pay-back has been achieved by the owners of the gas field, when the overall position of the reservoir is more roundly considered, and after the developers have benefitted from the early return-on-investment and the infrastructure is all in place, nevertheless a great deal of certainty needs to be provided up front to ensure that development is indeed possible.

In some extreme circumstances, it could be possible to introduce into the GSPA options to reduce the term, volume or gas price if circumstances change in such a way that the Seller has achieved pay-back and/or if there is a need to re-appraise how best to develop security of supply in the market by enabling other fields to be developed. Under these circumstances, if the decision is taken by the regulator, rather than in negotiations between the Seller and the Buyer, consideration should be given for compensation to be given to the Seller, such as tax benefits/holidays, incentives to export gas to maintain volume share or potentially higher gas prices in the local market. Indeed, although many GSPAs include price re-openers, it is

²⁸ http://europa.eu/rapid/press-release_IP-18-4239_en.htm

very rare for a GSPA to include any kind of early termination clause, either one which is negotiated between the parties or imposed by regulators.

However, there is one element that is often included in a negotiated gas sales contract, and that is what is known as the Most Favoured Nation's Clause.

A Most Favoured Nation (MFN) clause in general is a level of status given to one country by another and enforced by the World Trade Organization (WTO). A country grants this clause to another nation if it is interested in increasing trade with that country. Countries achieving most favoured nation status are given specific trade advantages such as reduced tariffs on imported goods²⁹.

In GSPAs, MFN is a non-discrimination guarantee that obligates a Buyer or a Seller to treat their trading partners symmetrically in their pricing decisions.

Long-term gas contracts are necessary and have long been recognized as a tool to constrain opportunism, especially, when there is a specific investment that needs to be made. One has to remember that the inflexibility of these long-term contracts is a good thing because it prevents Buyers abusing opportunities in the future that may present themselves if such a contract had not been available, such as buying cheaper gas from a new source, when the Seller has to make huge upfront investments specifically for that client.

The disadvantage, however, of such long-term gas agreements is that their inherent inflexibilities may insulate the parties from shifting market conditions, leading to a divergence between the contract prices and societal opportunity costs. Indeed, the inherent inflexibility in long-term gas contracts leads to parties sometimes deciding to enter into shorter term contracts. Shorter term contracts are now becoming more the norm than they were previously. Sellers, however, that have to invest huge sums to develop new fields, LNG liquefaction facilities and/or large pipeline projects, still prefer, if not even require, long-term commitments from Buyers.

One of the primary challenges thus in GSPA contract design is to craft an agreement, which permits prices and quantities to adapt to changing economic realities, without introducing the spectre of unconstrained opportunism. MFN clauses, which condition the contractual price on local and regional market conditions, may serve just such a purpose. Thus, long-term gas contracts often

²⁹ <https://www.invesTOPedia.com/terms/m/mostfavorednation.asp>

include such MFNs, which are non-discriminatory guarantees that obligate a Buyer or Seller to treat all trading partners (or some specific ones named in the contract) symmetrically in pricing decisions.

When worded, the MFN clause may stipulate that the contract price has to be equal to the lowest price charged in a particular region. This ensures that the Buyer benefits from the price reduction that the Seller might concede to other customers in the future. Similarly, a requirement that ties the price to the highest price offered in an area affords the Seller protection from a Buyer who may later on offer selective price increases.

MFNs also differ with regard to the set of prices within the gas contract on which the adjustment is conditioned. In the case of a two-party Most Favoured Nation (2PMFN) clause, the prices considered are restricted to the set of those offered by either the contractual Buyer or Seller to the stipulated region. A much broader degree of protection is provided by the three-party Most Favoured Nation (3PMFN) guarantee, which ties the contractual price to that offered by any Buyer or Seller in that area. These are sometimes referred to as “Meeting Competition Clauses” (MCC).

While the duties imposed by an MFN clause are straightforward, their economic rationale is less clear. Indeed, MFNs can be regarded either negatively or positively:

- **Negatively:** it could encourage tacit collusion and/or be uncompetitive in nature if they favour the strong monopoly at the expense of smaller Buyers. This is why anti-monopoly authorities are often against it.

It could facilitate collusion in oligopolistic markets and could seem to be designed as a classic facilitating practice to reduce price competition with socially deleterious results.

- **Positively:** viewing MFNs as a mechanism designed to increase efficiency by introducing price flexibility in long-term contracts. Indeed, a primary limitation of long-term contracts with inflexible prices is that it isolates the parties to the exchange from market-determined opportunity costs. MFNs help to facilitate efficient price adjustments in extended relationships. Insofar as the MFN clause permits the contract price to reflect the cost of substitute supplies and enables the parties to the contract to be confronted with more precise signals of societal costs when making their production and consumption decisions, under such conditions they would be regarded as

increasing the efficiency of the contractual exchange. Most importantly, it is done without the intervention of regulators.

Case: Most Favoured Nation's Clause - Israel

One of the most vociferous debates that took place in Israel from the time the Tamar gas partners signed their main GSPA in 2012 with the state electricity monopoly Israel Electric Corporation (IEC) is regarding the natural gas price agreed between the parties. The price which was agreed in 2012 was \$5.04/MMBtu with a linkage mechanism to the US Consumer Price Index (CPI) +1% a year from the start of supply in April 2013 until 2019 and -1% from January 2020 and thereafter until the end of the 15-year contract.

The GSPA also included two price re-openers: price adjustments could be made on the 8th and 11th year after commencement of commercial gas supplies. The sale's price could be increased or decreased by 25% of the existing sale's price during the first adjustment period, and by plus or minus 105 during the second adjustment period of the then-existing sale's price.

The price re-adjustment could be achieved via negotiations between the Buyer and the Seller. If no agreement regarding the price adjustment is achieved, the issue is to be settled by arbitration in Israel, if the sum is below a certain amount or in London if the sum is higher.

The reason how and why this indexation mechanism was chosen, itself became a matter of controversy. Certain quarters insisted that it was dictated by the regulators in Israel who were concerned that the fuel price of the main electricity provider would be bound by the vagaries of oil price hikes around the world, which can be caused by the onset of storms (climate or political), and preferred a stable price indexation, linking it merely to the CPI. Others insist that the +/- 1% mechanism part of the price indexation was a request by the Israeli Sellers to help them finance the project during the initial 8 years.

What is certain is that both the Ministry of Finance and the Electricity Regulator (PUA) approved the indexation mechanism and even vouched for it during a parliamentary debate on the issue (Knesset minutes in Hebrew 4.7.2012).

During the negotiations of the GSPA, IEC asked to include an MFN clause in the contract. The Antitrust Commissioner, however objected to this, as he preferred supporting the private power sector (IPPs) in Israel and did not allow IEC to include this clause in its gas contract.

In additions, the Sellers had the right to cancel an option they had offered IEC to buy more gas at a later time, with a lower indexation mechanism (30% linked to the US CPI and not +/-1% mechanism for any volume of gas higher than 24,000 MMBtu/hour), prior to the exercise thereof, in the event regulators would impose gas price control in Israel (as the term is defined in the GSPA), whose result will be the reduction of the purchase price.

The Tamar partners also sold gas to private electricity producers (IPPs). The gas price in the IPP contracts was about 10% higher than that of IEC when these were originally signed. The indexation of the gas price in these contracts was based on the electricity generation tariff, which was regulated by the electricity regulator – the PUA.

Although, the pendulum could have swung either way, what has in fact happened in the interim period is that because of the different indexation mechanisms that were agreed by the different Buyers from Tamar (and in the absence of the main Buyer IEC having an MFN clause), the gas price that IEC paid (at the end of 2018) was considerably higher (\$6/MMBtu) than that of the much smaller IPPs (\$4.8/MMBtu).

The consequence of this decision is that IEC which is the state utility electricity supplier to the entire market, including to all residential consumers, was burdened with a gas contract that has a higher natural price than its competition, whilst the IPPs that supply electricity to large industrial consumers, benefitted from a much lower price (as the generation component fell for a variety of reasons whilst IEC's price was increasing at about 2%-3% a year). In addition, there was a growing number of IPPs whose gas price is linked to the electricity generation price of one electricity generator – IEC, whose market share is falling each year.

A further consequence of these decisions is that once global oil and gas prices started to fall in 2014, the gas price in Israel paid by IEC, which in 2012 was half that of the price in Europe and a third to quarter of that in Asia, was in 2016 and 2017 on a par with or even higher than other major gas markets. In 2018, international gas prices once again rose, only to fall back by about 40% in Q12019.

This in turn led to an outcry by both IEC, the public and some regulators. This was combined with demands to re-open IEC's contracts, impose price controls and the lodging of class action law suits. All this contributed to giving Israel's gas sector an unstable reputation.

This is the place to state that price control on natural gas have been attempted at different times in different countries usually leading to failure on many levels, including in bringing the 'right price'. Thus, western countries, like in the US, UK, Holland and others, where price controls were imposed, these were cancelled within a few years. In addition, price control is anathema to fostering competition.

The relevant ministries in Israel, specifically the Ministries of Energy and Finance, resisted the temptation and the pressure of imposing such controls (beyond 'soft' price control as enacted in what became later known as the "Gas Outline" in Israel, which set future gas prices based on existing prices, until the market would open up for competition in 2021).

Had the regulators in Israel, more precisely the Antitrust Commissioner agreed to allow an MFN clause in the IEC GSPA with Tamar, the clause would have ensured that IEC would always get the cheapest gas price sold by Tamar and none of the hysterics.

Equilibrium of power between Buyers and Sellers

One of the most important things when writing a long-term gas contract, is to establish a balanced equilibrium of power between the Buyer and the Seller and to ensure that this balance is maintained throughout the term of the contract, which can be as long as 20 years and sometimes more. Indeed, long-term and high-risk gas sales and purchasing contracts should in fact not have any unilateral rights given to only one side.

As the main and first Buyer of gas from Tamar, IEC represented the credit-worthy anchor Buyer that enabled the owner and financial institutions to move ahead with the development of the field. It is thus right that this contract should keep the Sellers whole until they have in the very least recuperated all of their expenses, not only in this particular field, but company-wide. Indeed, the success of one field can only be measured as part of the greater picture that includes past oil and gas exploration failures in both Israel and abroad, future operational expenses of the field in question and further exploration operations to maintain the company's production-to-reserves ratio as well as the country's resource base.

If one moves then ahead beyond the launch contract (Tamar to IEC), then it can be argued that the launch/anchor Buyer (IEC) could be expected to potentially benefit from some of the better terms that are introduced in later contracts with

other Buyers (e.g. IPPs). Namely, although it is potentially acceptable that the launch and biggest client has to swallow the more ominous terms to get the ball rolling, it is arguably fair towards such a Buyer to establish a market environment where early contracts can benefit from later developments of new contracts, or new circumstances. In this manner, the anchor customer is not always penalized for being the launch/anchor and the biggest customer.

Thus, there is an argument to be made for more flexibility after a certain amount of years have elapsed when there could potentially be ways for Buyers to recoup once the Sellers' gas field is up and running. The way to ensure this, however, is not by knee-jerk emotional re-actions by state regulators, under pressure by the public and the media, coming to the rescue of the state monopoly by imposing new contractual terms years later if conditions have per chance changed to the detriment of said anchor Buyer.

Instead, the manner that the gas world copes with these issues is either by sticking to the terms of the contract, which is the norm in the majority of gas contracts, or by the sides mutually agreeing to re-open the negotiations and potentially reaching a compromise by which the Seller might agree to a lower price if market conditions have changed drastically in return for the Buyer potentially offtaking greater volumes of gas. It is true, however, that some of these "agreements" have also been fostered by parties going to court.

Other means of dealing with changing market conditions are, as stated above, by having pre-agreed price re-opener dates (which the IEC and Tamar contract has in July 2021 and July 2024.).

The best means, however, would have been to allow the sides to include an MFN clause in the GSPA. Instead of adopting the course of action which the government of Israel took, a much fairer way would have been for the regulators to agree to include a Most Favoured Nation clause in the original contract, where rigid non-flexible terms were required to get the development of the Tamar field started. This would offer the dilemma of choice and is shared equally between the Buyer and the Seller.

Under the MFN model, the commercial dilemma is there for the Seller to decide. Indeed, the Seller is faced with a decision to sell another tranche of gas to increase its volumes (and thus increase its NPV), knowing that it will affect its original contract (and reduce its ROI). But this is a dilemma that must be taken by the Seller and not imposed arbitrarily by governments or regulators.

This is the positive way to develop gas markets for all concerned.

Case: Gas price of IPPs in Israel linked to the power generation tariff

Regarding the gas price indexation of the IPPs in Israel, this too was amiss in that, with the different linkage mechanism by IEC and by the IPPs and the lack of an MFN clause for the biggest anchor Buyer (IEC), the market in Israel became distorted.

The gas price of the IPPs in Israel was linked to IEC's power generation tariff (remember that the gas price which formed a significant element of the electricity generation tariff was indexed to the US CPI). Thus, in practical terms most of the electricity market's gas price was linked to the US CPI. The linkage of the IPPs' gas price to IEC's power generation tariff means that changes in their gas price are determined by the electricity regulator, the PUA, based on parameters that are mostly not connected to gas fundamentals (such as coal price or taxation). This in turn is the key factor that determined the profit rates of the IPPs.

In addition, the gas indexation formula of the IPPs in Israel is delinked from global energy or gas prices, from alternative fuels in Israel and does not take into account the exploration and development costs for new gas fields to replenish reserves.

Having a gas price linked to the electricity generation tariff is usually only possible where electricity itself is sold on a traded market, or where there is a long-term PPA with a power Buyer that is not subject to price controls. This is not the case in Israel, since (as of the writing of this study) the electricity prices are fully controlled by the regulator - the PUA.

4.15 Additional points of negotiations

Below are some additional useful pointers in negotiations of GSPAs:

- Each party should evaluate all the major outstanding GSPA issues in a detailed risk matrix and establish some notional values for these items.
- On the basis of the above, parties decide on a 'trading' strategy for subsequent negotiations for new drafts of the GSPA. This is done by allocating the outstanding issues to categories of importance or value and

decide which can be traded away to the other party and what could be obtained in exchange. This will of course differ depending on the players, such as an LNG Buyer with little flexibility to divert cargoes, might for example, ask for more leeway on volumes.

- A good idea is to write a matrix of all termination clauses and how these are invoked and what are the remedies for each. This will help to ensure that the GSPA does not include different or contradicting iterations.
- Need to ensure, if possible, that there is a balance of risks between Buyer and Seller. For example, understand how much CAPEX/OPEX is to be spent by each party in order to be able to fulfil each side of the contract; understand if one party is more exposed to risks/has more options available to it if something were to go wrong during the term of the GSPA. If Seller is more exposed because it has fewer options to sell its gas than the Buyer has to buy gas throughout the term of the contract, or if the Buyer is more likely during the course of the contract to have access to lower priced gas either from its own sources or from another Seller than the Seller has access to a higher priced Buyer. Another issue to look at in this respect is if the Buyer has a strong position to influence its host country and cause an FM or other lesser threshold of termination (e.g. Political Risk Event if there is such a clause in the contract) to be activated, then under these circumstances the weaker party needs to negotiate to receive mitigation of some of its major risks under the GSPA.
- These issues are especially important if the GSPA is a transaction signed between parties in two different countries, with two different host governments. However, each side also needs to consider its bargaining strength vis-à-vis the other party, to realize what it can obtain or not. Namely, although one party (e.g. the Seller) might be more exposed, it might also be in a weaker negotiating position and thus not able to get the guarantees it would ideally need and may decide to proceed in any case with signing the contract.

5. LNG CONTRACTING

Long-term contracts have long dominated the international market for LNG³⁰. Since 2000, however, the proportion of LNG-traded spot or under short-term contracts has grown substantially, while long-term contracts have become more flexible. With new LNG supply having come/coming online between 2015 and 2020, buyers demand smaller and shorter contracts with a greater degree of flexibility than before.

From 2014 through 2017, LNG buyers had increasingly been looking to sign shorter, smaller and more flexible contracts. In 2017, out of 30 GSPAs examined by Poten & Partners, 20 were for less than 5 years. This represented a major shift away from veteran 20-year contracts, making 10-15-year contracts now look long-term. Poten & Partners also noticed that the average volume per deal has been falling in tandem with contract lengths: in 2017, it was below 0.7 million tpy, compared with 0.9 million tpy in 2016.

According to Shell³¹, that trend changed somewhat in 2018 with the average length of contracts signed more than doubling to about 13 years in 2018 from around six years in 2017.

Currently, most LNG still remains locked up in long-term contracts priced off crude oil indices like Brent. Just 27% of total traded volumes, or around 77.6 million tons, was sold on a spot or short-term basis in 2017, according to GIIGNL. Pure spot deals - for deliveries within three months of the transaction date - accounted for 59 million tons, or 20%³².

Buyers also have the ability to draw from a pool of displaced LNG suppliers that have not committed to any end-user, which is expected to account for about 20%-25% of the market over the medium term. According to Poten & Partners, 39 of the 40 deals in 2017 drew from this pool of homeless LNG. With buyers having this option for the next decade, there seems to be less of an incentive for them to commit to long-term contracts that have less flexibility. Buyers have growing opportunities, and have clear expectations when it comes to competitiveness, affordability and returns, and with an attractive portfolio of new supply options, they

³⁰ Hartley, P., The Future of Long-term LNG Contracts. Available from: https://www.researchgate.net/publication/272416905_The_Future_of_Long-term_LNG_Contracts [accessed Apr 28, 2018].

³¹ Shell Outlook 25.2.2019

³² <https://giignl.org/publications#webform-client-form-1161>

are now more than ever better able to select the most competitive sources of supply.

There is a growing trend for flexibility in LNG agreements, according to Bracewell partner John Gilbert, who focuses on disputes in oil and gas. “In the past, disputes were almost exclusively about price and looking to move from crude or change the index. This has changed to a focus on flexibility, enabling sellers to reduce the volumes supplied, or not to supply at all, to allow them to chase better price opportunities elsewhere”³³, he said.

The calls for enhanced flexibility are a result of a more liquid LNG market. Flexibility is a key concern for buyers, who are likely to be more attracted to destination-free volumes from FLNG projects provided under shorter contracts. Technical concerns over reliability will be overcome if the projects prove they can make regular deliveries.

This shift away from long-term contracts is putting buyers, sellers and investors at odds, and endangering the next wave of LNG projects. Indeed, in its outlook for 2019, Shell added that there was now “a mismatch between suppliers and buyers contract needs, possibly preventing some developers going ahead with their projects”.

The LNG industry is increasingly concerned about the recent slowdown in final investment decisions (FIDs). Investors have traditionally been confident in providing support for projects with long-term deals and so reduction in the term of contracts has led to fewer FIDs over the last few years.

As explained by World Gas Intelligence, “cost reductions, designed to ensure gas is competitive, are key to taking final investment decisions (FIDs) on new LNG projects, with the need for further cuts seemingly uppermost in suppliers’ minds. Less than 10 million tons per year of capacity were sanctioned in 2016-17, and only 21 mmtpa were sanctioned in 2018, according to Giles Farrer, Wood Mackenzie Research Director. In 2019, however, the global LNG market is rebalancing, with Farrer explaining that it will be “a record year in terms of LNG project sanctions, with more than 60 million metric tonnes per annum (mmtpa) of new capacity likely hitting the final investment decision (FID) stage” (which in turn will have an impact on gas pricing as demand will probably fail to keep pace with supply in the short term). By the first half of the 2020s, demand growth is likely to eat into the new supplies coming on line and new projects will need to be

³³ Interfax 20.9.2018 Andrew Walker

sanctioned in 2019 to meet this demand. In fact it is estimated by Shell that 21 mmtpa of FIDs need to be taken every year to meet growing demand for LNG up to 2035.³⁴

Asian buyers' push for shorter, more flexible contracts, and price linkages more reflective of regional supply and demand fundamentals, has spooked lenders and project financiers accustomed to long-term, oil-indexed deals that have characterized the industry. As a result, most of the LNG projects likely to go ahead over the next year or so (and two of the three projects that took FID in 2018) are being driven by major producers that are less reliant on long-term financing, and can if necessary, take LNG into their own portfolios, and are more likely to attract buyers as equity partners".³⁵

In addition, the growing role of aggregators in the natural gas market that can take volume and price risks is increasing. Total Senior Vice President of Global LNG Philip Olivier explained that "aggregators, or portfolio players, are perfectly positioned to meet buyers' demands for different price indexation, more seasonal and flexible supplies, and shorter contracts, and can help emerging markets deemed too risky to sign bankable long-term contracts."³⁶

Buyers seem equally enthusiastic of this trend. The chief fuels transactions officer at Japan's Jera, Hiroki Sato, said the portfolio model is good for the industry as it satisfies lenders and helps buyers, especially in emerging markets. Midsize IOCs (independent oil companies), however, feel a degree of stress by this growing dominance of portfolio players, with concerns about being crowded out as more supply is concentrated in the hands of a few deep-pocketed western majors and national oil companies.³⁷

In response to a question on how companies can finance large LNG projects without long-term contracts, Dumitru Dediu, the head of McKinsey's Global Gas and LNG Group, responded that "going forward, if you assume the market to be fully liquid then why do you need sales-and-purchase agreements? Can't you just take FID on spot deliveries? And the answer is generally the investments are a bit chunkier and currently because of the intrinsic nature of LNG you cannot store it and you can end up with stranded cargoes – you want to have a certain degree of secured offtake. For operational reasons you want to ensure that that is the case. So that's why I think the transition is going to be step-by-step and not going

³⁴ OEIS Podcast, Shell's LNG Outlook 2019, 18.3.2019, interview with Jeff Edwards, General Manager at Shell Energy responsible for global LNG market analysis.

³⁵ World Gas Intelligence, 26.9.2018, Cost Cutting Drive Hits Speed Bumps, Jaime Concha and Jane Colin

³⁶ Platts October 2018

³⁷ World Gas Intelligence, 13.3.2019

to come suddenly. But yes, we see a lot of FIDs being taken with 60-70% secured offtake and the rest is all spot. I think the market is moving in this direction”.³⁸

Dediu continued to explain that “at McKinsey we have this LNG buyers’ survey: we interview 85% of the market, and we ask a number of questions around contracting. One is how much short-term versus long-term do you want to have in your portfolio. And what you see is that a lot of buyers want to have 40-45% short-term, which is nearly double today’s 20-25% in short-term LNG. If you are to think as the buyers do, and assuming this is a buyers’ market for the next 1-4 years, the buyers might get their way and we might see more short-term”.

There is thus a shift, which has been described by Jeff Edwards, General Manager at Shell Energy responsible for global LNG market analysis “towards more diversity of types of projects: projects with strong sponsors that perhaps don’t have the need for project financing and a strong ability to place their volumes through their portfolio into the market may take one approach towards developing capacity, whilst other projects that need project finance may need to sell more long-term contracts into the market”.³⁹

According to Poten & Partners, around 80% of existing contracts are going to expire by 2030, with about half of the market consisting of new supply and half being renegotiated. There are thus opportunities for change in contracting types.

Balancing these competing expectations and requirements will be a challenge for the LNG business. However, with LNG demand rapidly growing and new FIDs having been slow to materialize over the last few years, there are also expectations in some quarters that long-term contracts will continue to play a certain role in the coming years, especially for more risk-averse offtakers. However, those buyers that agree to sign a new contract (or renew an old long-term contract) will most probably insist in the very least on preserving their demand for greater flexibility such as not having destination clauses.

The limitations imposed on shipping destinations in legacy LNG contracts, are a barrier to flexible deals. If flexibility is introduced in the shipping destination, it makes it easier for purchasers to cooperate amongst them in adjustments to handle short-term demand variations. Buyers are increasingly asking to ensure that such adjustments are made possible both between buyers from different projects as well as buyers from the same project. On another front, as the LNG market becomes more flexible, both sellers and buyers will need to have greater

³⁸ Interfax 26.9.2018, Long-term LNG deals will continue to decline, Thomas Hoskyns

³⁹ OEIS Podcast, Shell’s LNG Outlook 2019, 18.3.2019

storage capacity to enable more flexible operations. In particular, sellers have virtually no spare storage capacity, and will have to do more to improve this service.

On the other hand, as LNG market dynamics are once again changing back as the market tightens again as fewer FIDs are taken on large scale LNG export projects, some producers are resisting even the move to remove destination clauses.

Until a few years ago, LNG producers held most of the cards in contract negotiations vis-à-vis buyers. Within the space of a couple of years, as more cargoes came out of Australia, and as US sourced LNG started to hit the markets in February 2016, with Russia adding 11 mmtpa of capacity in 2018 at its Yamal LNG facility and with Qatar announcing in September 2018 an end to its moratorium and is expected to reach 110 mmtpa export capacity once the country's fourth new mega-LNG train comes on line, markets started to swing towards being a buyer's market, but by the mid-2018, markets seemed to be preparing for a swing back to a possible scenario of supplies being thin.

As explained by Argus⁴⁰, although many new LNG export facilities are being constructed, "demand for LNG can catch up quickly with supplies. This is because it is much quicker, easier and cheaper to build import LNG onshore or FSRUs offshore than to construct export onshore or offshore FLNG facilities. Strong demand from China and India has so far been able to absorb new supplies, and new opportunistic markets (e.g. Pakistan, and Egypt between 2015 and mid-2018) can quickly take up supplies when offered at attractive prices". Argus explains that although it is still a plausible scenario in the future that the market will become oversupplied, it has not even reached step 1 of the 3 criteria that characterize an oversupplied global gas market.

A tightening market may lead to longer-term contracts coming back into favour, with some buyers starting to sign longer-term deals again after holding off while the market was in an apparent glut, although Platts reported that even in March 2019 "Asian participants at a conference in Singapore were talking about 50% of their contracts being short term by 2025," adding that "although that is wishful thinking, it shows the mood."⁴¹ It certainly appears that the fluidity of the global LNG market has increased such that a range of contracts and pricing will be the norm, even if it will be a while before oil indexation in LNG pricing fully disappears.

⁴⁰http://blog.argusmedia.com/zombie-lng/?utm_campaign=shareaholic&utm_medium=email_this&utm_source=email

⁴¹Platts, Lucie Roux, Russia needs to unify LNG and gas export strategy: Mitrova, 22.3.2019.

Royal Dutch Shell, the world's number one LNG portfolio player with assets covering the entire value chain, has also been a strong proponent these last couple of years that the global LNG market is not oversupplied, and is even forecasting a shortage. Shell explains that “the mismatch in requirements between buyers and suppliers is growing. Most suppliers still seek long-term LNG sales to secure financing. But LNG buyers increasingly want shorter, smaller and more flexible contracts so they can better compete in their own downstream power and gas markets. This mismatch needs to be resolved to enable LNG project developers to make final investment decisions that are needed to ensure there is enough future supply of this cleaner-burning fuel for the world economy”⁴².

There is both a growing demand for LNG, coupled with an increasing number of players in the LNG market, and these combined with technical innovations (e.g. FSRU, FLNG) means that it has become easier for buyers to obtain more flexible contracts than ever before. However, it is also true that new projects need the ability to reach FID in line with demand in order to ensure the long-term sustainability growth of the LNG market. To achieve this, they need guarantees of cash-flow like those that were provided by veteran credit-worthy buyers through conventional long-term contracts. Indeed, although spot and short-term LNG markets are good for making the most efficient use of existing facilities, such contracts on their own make it difficult to commit massive amounts of money needed to construct new LNG (or capital-intensive pipeline projects for that matter), which still need a guarantee that the buyer will take delivery of a certain amount of gas.

In order for the LNG market to develop and expand, to suit both buyers and sellers, there must be a combination of long and short-term contracts in an appropriate balance. All parties involved in such projects must play their part in maintaining the momentum. Although LNG buyers are no longer as willing to accept rigid contract conditions, it may be possible to find solutions where sellers and buyers collaborate in an acceptable risk-sharing scheme for new projects.

In addition, as LNG spot deals need to be concluded quickly, setting in place a standard contract would facilitate such deals, rather than the regular GSPA negotiations used in long-term contracting and supplies.

New transactional relationships need to be constructed between all the players: sellers, buyers and financing institutions. This means that when setting up a

⁴² <https://www.shell.com/media/news-and-media-releases/2018/shell-sees-potential-Ing-supply-shortage-as-global-demand-surges.html>

project, the risks must not be too one-sided, but rather apportioned appropriately between the parties.

The Japanese LNG buyer TEPCO, has itself expressed a willingness to explore some of these matters, including participation in upstream projects and actively investing in LNG tankers. TEPCO understands that although they desire flexibility, that “the project base still needs a certain level of long-term quantitative commitment to ensure a reliable cash flow for the project sponsors”.

Liquidity and market depth is all part of an efficient market. It is not just the buyers who can procure short-term, sellers can also benefit. They can optimise by having a portion of their output reserved for long-term supply and some short-term cargoes for sale on spot or a few months ahead. It’s more of a portfolio approach, and as buyers and sellers get accustomed with that it’ll end up just being how they do business⁴³.

Insofar as the lenders are concerned, if the banks that lend the funds can take into account the fact that short and spot transactions for LNG will grow, and the consequent potential for on-selling, and are reassured that this provides a means to securing the necessary cash-flow, it should then be possible to relax the rigid Take or Pay clauses used in the past, so that a portion of the risk is taken by some of the lenders.

6. GAS PRICING

6.1 Introduction

In this chapter, I am referring to those gas prices that are determined based on negotiations as part of the GSPA process. This is not the case for all gas sales, as still in 2017 some 30% of gas sold and consumed around the world is done at a price that is regulated. The International Gas Union (IGU), a world-wide non-profit organization which has conducted wholesale gas price surveys for the last decade, differentiates between 9 types of price formation mechanisms (see table below), including 3 different categories of prices set by regulation: regulation cost of service, regulation social and political and regulation below cost⁴⁴.

⁴³ World Gas Intelligence, 4th July 2018

⁴⁴ Wholesale gas price survey, 2018 edition. A global review of price formation mechanisms 2005 to 2017, June 2018. <https://www.igu.org/news/wholesale-price-survey-2018-edition>

Regulators at times control or set the price of gas that customers in some or all sectors pay in a certain market. Although this can be regarded as an ‘acceptable’ practice when the seller is a National Oil Company (NOC), if International or Independent Oil Companies (IOCs) are involved, any kind of price regulation can undermine their trust that any promise they are given at the initial stage of their investment may be broken by the time they sell their gas. This is a strong reason not to impose price controls in those markets that want to attract IOCs, as it may limit the number of independent and international players willing to invest in such a market.

If one refers however only to international trade (namely the sum of all pipeline and LNG imports/exports), volumes which represent 30% of total global gas consumption⁴⁵, then all these are done based on three pricing mechanisms known as: oil price indexation (46%), gas-on-gas competition (49%) and bilateral monopoly negotiations (5%).⁴⁶

Spot prices, such as spot LNG cargoes sold into markets where there are no trading hubs, is defined by IGU as the “price of the cargoes reflecting the current supply-demand situation”.

I recommend to anyone wishing to understand more about global gas prices and linkage mechanisms and how these have evolved over the years, to download the IGU report which is published for free on an annual basis.

Types of Price Formation Mechanism (IGU)

Oil Price Escalation (OPE)	The price is linked usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used as can electricity prices
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a

⁴⁵ Global gas consumption in 2017 was 3,670.4 bcm out of which 740 bcm was traded globally via pipeline and 740 bcm as LNG

⁴⁶ Ditto IGU report.

	<p>short-term fixed price basis and there will be longer term contracts, but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category are spot LNG cargoes, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple Buyers and Sellers.</p>
<p>Bilateral Monopoly (BIM)</p>	<p>The price is determined by bilateral discussions and agreements between a large Seller and a large Buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Usually there would be a single dominant Buyer or Seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple Buyers and Sellers trading bilaterally.</p>
<p>Netback from final product (NET)</p>	<p>The price received by the gas supplier is a function of the price received by the Buyer for the final product the Buyer produces. This may occur where the gas is used as feedstock in chemical plants, such as ammonia or methanol and is the major variable cost in producing the product.</p>
<p>Regulation: cost of service (RCS)</p>	<p>The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the “cost of service”, including the recovery of investment and a reasonable rate of return.</p>
<p>Regulation: social and political (RSP)</p>	<p>The price is set, on an irregular basis, probably by a Ministry, or a political/social basis, in response to the need to cover increasing costs, or possibly as a</p>

	revenue raising exercise – a hybrid between RCS and RBC.
Regulation: Below cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas, often as a form of state subsidy to the population.
No price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
No known (NK)	No data or evidence

Below is my summary of IGU’s pricing formation mechanisms divided into percentages for gas consumption, gas production & global gas trading (pipeline and LNG) for 2017.

	GOG	OPE	BIM	NET	RCS	RSP	RBC	NP
Consumption	46%	19%	3%	-	11%	14%	6%	1%
Production	45%	9%	2%	-	15%	20%	8%	1%
Pipeline Imports	61%	31%	8%	-	-	-	-	-
LNG Imports	28%	72%	-	-	-	-	-	-

6.2 Price Negotiations in a GSPA

Conventional wisdom is that price – and the associated terms of escalation, price re-openers etc. – are left until last in GSPA negotiations. Why? For the reason that until all other significant items are settled, it is difficult for either Buyer or Seller to ‘value’ the GSPA as a whole and decide what price to attach to it. This does not mean that other clauses cannot be re-opened during the price negotiations stage, or at any other time, before an agreement is executed. If Buyer and Seller are just so far apart in a price negotiation, it may be impossible to reach an agreement without renegotiating some other significant value item in the GSPA that had previously been ‘agreed’. Remember the negotiator’s maxim: ‘nothing is agreed until everything is agreed’.

Case: When might it not be a good idea to leave price negotiations until last in the GSPA negotiations process?

Example #1 - It is possible that you may have no choice in the matter. As a Buyer, you may have submitted a tendered bid for some gas which includes offering a price (and escalation terms) against a Heads of Agreement summarising the anticipated main terms in a final GSPA. However, this still doesn’t preclude some negotiations on price if the final GSPA terms do not end up being entirely satisfactory.

Example #2 - If you are a Buyer in a competitive negotiation for gas against other Buyers and your assessment is that market conditions are tightening with decreasing supplies in the immediate future, then you may wish to agree a price at an early stage to lock in the Seller. Otherwise, you may risk being left in an auction with other Buyers, as all competing negotiations reach a conclusion.

Obviously, as a Seller you would view the situation completely differently and would only seek to agree a price early in a negotiation if you expected market prices to soften with the arrival of competing supplies during the timeframe of your GSPA negotiations.

Most gas prices, as agreed in GSPAs, remain confidential to the parties only.

6.3 Elements of gas pricing

Natural gas, as opposed to oil, is not a commodity with a global price. Rather prices are set on a regional/local area basis and are often the result of extensive negotiations. The price that is reached will depend on a host of factors: whether the gas is produced onshore, offshore, in shallow/deep/ultradeep waters, the quality of the gas, technological advances in upstream, midstream and downstream, whether it is dry gas or associated with oil (i.e. gas produced alongside crude oil), the existence of transmission/distribution infrastructure, supply and demand, strength of Buyers and Sellers, the type of client (e.g. a power station may be able to afford higher prices than an ammonia plant), the level of competition, market/public pressure, the level of governmental support, tax regimes, assumed political risks, whether the gas is supplied via pipeline or as LNG, the existence and price of competing fuels in the market and the affordability of gas in any particular country, environmental and/or carbon emissions concerns combined with carbon pricing, even the timing of peak gas demand and to what extent fossil fuels in general and gas in particular retain a foothold through adoption of technologies to reduce emissions such as the implementation of carbon capture and storage schemes (CCS) and other factors.

Aspects of upstream gas pricing include all or some of the following elements: base price, indexation mechanism, floor and ceiling prices, a constant/fixed element in LNG sales, lag periods, price previews or re-opener clauses. The price of LNG is set either FOB or DES, and in both cases is quoted prior to regasification.

The final price that is achieved should neither be too low or too high. If it is too low, it can lead to the misuse of the resource (e.g. establish high energy guzzling but uneconomic and unsustainable industries); gas wastage (using gas for space heating with poor insulation); thwart further exploration and development by IOCs

(as was the case in Egypt when prices were set at the low price of about \$2.6/MMBtu) and too low a Government Take (gas is a national resource and revenue should be set aside to benefit future generation or for example to invest in alternative energy sources).

If the price is too high, it risks distorting the rent allocation benefit between Sellers and Buyers (for indigenously consumed gas), or could cause gas to be priced out of the market leading to excessive consumption of lower cost more polluting fuels, or of cleaner renewables, combined with the development of energy storage and efficiency measures, leading to further erosion in gas consumption. If the price is too high in a certain market, this makes exports also more complicated in a global market that is becoming more competitive with an increasing ability to commoditize gas in the form of LNG.

The overriding criteria for gas pricing should be economic efficiency, and the first step in setting or changing gas prices is to determine the economic price of gas in the particular country or region in question⁴⁷.

6.4 Gas price indexation

During the negotiations process, once the parties to a GSPA have agreed a price for the gas (base price), they will typically agree that the price will change over time, in accordance with a reference that both parties believe will – for the most part – give them a commercially acceptable price for the volumes of gas bought and sold throughout the term of their contract.

The indexation reference is typically either:

1. A hub at which gas is traded – both physically and virtually⁴⁸ – where a published and transparent price for gas is available readily and reliably.
2. Based on Oil Price Escalation - the price of oil, other fuels, or a basket of other relevant fuels (themselves with reliable published transparent prices) - to which the gas can be linked via an indexation formula.
3. Some other published index of prices – such as consumer price indices (CPI), or indices of labor costs in manufacturing, or referenced to wholesale electricity prices.

⁴⁷<http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2001/Data/PAPERSVO/SESSION1/Ps1-sp-e.pdf>

⁴⁸ A physical hub is a distribution point located on a natural gas pipeline system, A virtual hub is a virtual trading point – at which gas is bought and sold in spot and forward trades.

The vast majority of gas that is traded around the world is priced according to negotiations that use either 1 or 2 above.

What is important to achieve in GSPA negotiations is that the change in gas price, driven by the indexation, must continue to reflect the original commercial balance of value that the parties had originally agreed. Ideally, the prevailing price will then continue to be at a level that both enables the volume of gas to continue to be sold and used in the final end-market over the length of the contract and assures a return of the gas producer's investment and reimbursement of operational and financing expenses.

To ensure that these principles are met, long-term contracts also sometimes contain renegotiation provisions (see below) which specify that the Buyer and the Seller will negotiate in good faith to restore these conditions, if for any reason the indexation mechanism should fail, in the view of either party, to keep them whole. In fact, contract renegotiating and price re-openers are trends that have increased recently.

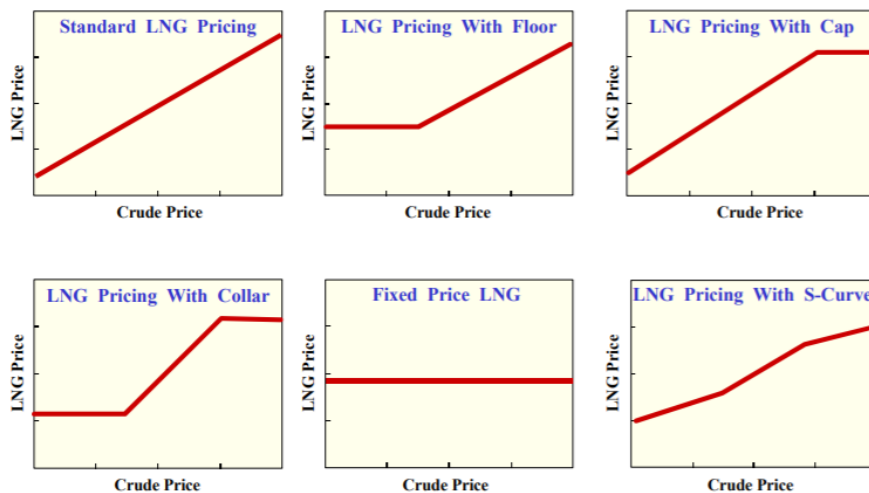
What is most important is that the reference index used must be outside the control or influence of each party to the contract, or even of the sphere of influence of the local regulator or government. Failing this, one would be back in the realm of regulated prices.

LNG pricing

Outside of North America (where gas contracts are usually priced using the Henry Hub gas market price), many LNG GSPAs were priced using formulae with a base price and indexation referring to competing sources of energy like Brent oil, fuel oil, gasoil, and coal. More recently, some LNG GSPAs or SPAs have been priced using gas hub prices or using formulae with a mixture of hub prices and alternative fuels. The contract price may also be linked to other economic indicators such as inflation or tax rates.

Most, but not all, LNG prices include a constant/fixed element (usually ranging between \$0.5-\$1/MMBtu), to take account for the relatively fixed infrastructure element for the LNG.

Typically, LNG pricing scenarios are as follows:



49

According to S&P Global Platts, “LNG’s pricing and non-pricing evolution is underpinned by a combination of important global supply and demand drivers”, as follows⁵⁰:

- **Increasing non-oil competition for Asian LNG:** Legacy Asian LNG procurement has been dominated by oil-price linked contracts, partly because oil represented the substitute fuel to LNG in some buyers’ energy mixes. However, for important fast-growing LNG importers, e.g. China, India and across Southeast Asia, non-oil fuels, including coal and renewables, are often the primary alternative to LNG. For these growing LNG importers, oil-price linked LNG contracts are therefore becoming fundamentally less important.
- **Increasing flexible procurement, reducing LNG contracts’ length and size:** Unlike when contracts were initially negotiated, ‘foundation’ sellers and buyers no longer require offtake and supply surety to secure project funding. They are therefore free to contract for shorter periods and size. North Asian LNG buyers, particularly Japan, face ongoing uncertainty regarding the future of nuclear plants, demographics and their impact on LNG demand. This, combined with the ongoing start-up of smaller LNG importers including Jamaica, Malta, Bangladesh, Bahrain, etc. has facilitated shorter, smaller contracting.

⁴⁹<http://www.ivt.ntnu.no/ept/fag/tep4215/innhold/LNG%20Conferences/2001/Data/PAPERSVO/SESSION1/Ps1-sp-e.pdf>

⁵⁰ S&P Global Platts, The rapidly evolving global LNG pricing matrix, 24.9.2018

- **Growth of destination-flexible US LNG supply:** The strong ongoing ramp-up of US LNG has already resulted in US cargoes deep penetration into the East of Suez markets. US LNG is typically sold on an FOB basis, allowing the cargoes to flexibly respond to country-specific demand fluctuations, unlike legacy point-to-point LNG contracts.
- **Legacy LNG contract expiry:** While the number of US and Australian contracts are increasing, total contracted LNG legacy volumes will decline dramatically post-2020. Many of these legacy LNG exporters possess insufficient gas reserves to renew their contracts at existing volumes/durations, while buyers are increasingly confident relying on the LNG spot market for security of energy supply.

Examples of indexations include:

Oil indexation

The choice of oil prices as a reference for gas prices has two main logical drivers:

- For a company that sells gas to customers that heat their homes, run their factories, or operate their power generation stations on various oil products – light heating oil, or heating fuel oil – then a price that stays competitive with the price of those products will ensure that the natural gas can continue to be sold in the market. Such a company (Buyer) is prepared to take the volume risk, as the price terms help it to protect its ability to market the gas and/or the secondary energy product it produces.
- For a company that is in the business of producing oil and gas, its shareholders are familiar with valuation based on oil prices and on the oil price risk. Such a company (Seller) is prepared to take the price risk, as its customer (Buyer) is assuring it of the volume offtake.

Thus, in general terms, the Buyer is willing to take the volume risk (because it knows the price it has achieved will enable it to sell the gas, or the output it produces from the gas, and the Seller is willing to take the price risk, as the Buyer is providing an assured volume offtake).

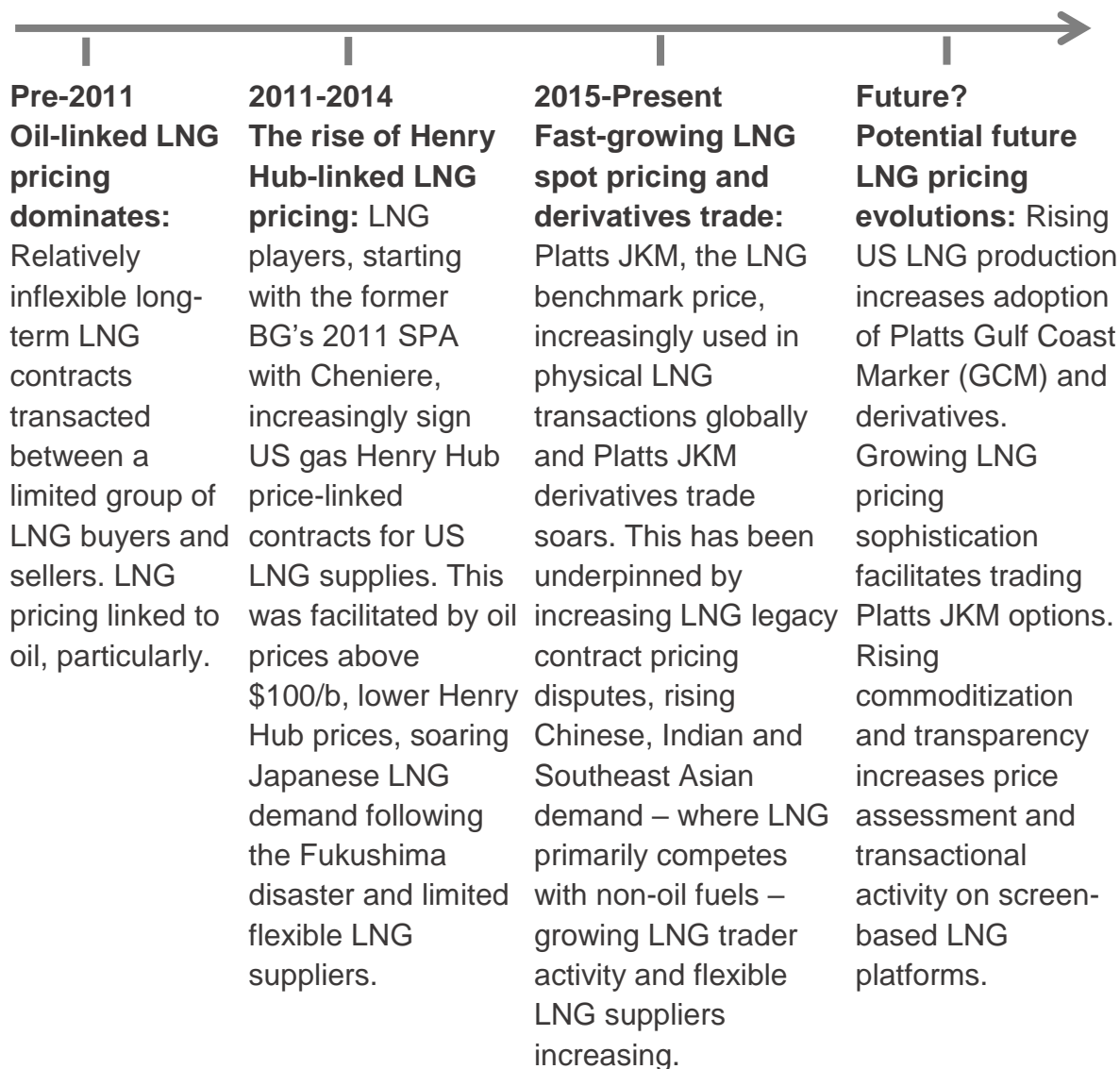
The parties to the contract reach an agreement on the balance of risks that each party is prepared to take. This could include not passing through the full value of changes in oil prices. Thus, as the price of oil rises, the Seller might get only some of this value, but as they fall, the Buyer might not receive the full benefit of the

decline. The parties also agree on the necessary conversion factors from dollar oil prices to local currency units.

The price of oil and oil products are outside the control of any one company, or indeed any one national regulator/government, and this is of fundamental importance to natural gas producers, selling their product (which as one recalls is not a commodity, at least not yet) to different countries. Where there is no market that sets gas prices by the interplay of supply and demand for gas itself, then a Seller's only protection against imposition of a price by a regulating government is to find an outside reference. Transparent, internationally traded oil prices are such a reference.

Thus, oil indexation is typically used where there is no local market for traded gas. This is normally the case in young greenfield gas markets, in markets where the main sources of supply are long distance LNG projects, and markets where there is no extensive meshed pipeline network which can provide a variety of choice to customers both in terms of where they bring gas into the system, and if necessary, where they can take it off. Oil indexation continues to be the prominent indexation used in Asian LNG & pipeline contracts, although going forward this may no longer be the case.

Asian LNG pricing evolution⁵¹



For several decades, except for the last give or take ten years, the formula of linking gas prices to oil product prices, dominated international gas transactions in most of Continental Europe. Even today, the world's largest long-term gas contracts, namely between Turkmenistan & China and Russia & China are both oil linked.

⁵¹ S&P Global Platts, The rapidly evolving global LNG pricing matrix, 24.9.2018

When European gas demand crashed in the recess following the 2008 global financial crisis, many European utilities struggled to meet their TOP commitments in their long-term contracts at oil linked prices, when crude prices were rising above \$100 a barrel. The resulting surplus of gas was a key factor in creating a hub-priced gas market.

Over the last few years, European contracts have gradually shifted to include more hub indexation, although the amount depends critically on the end market and supplier. Markets in northwest Europe have moved more towards hub indexation or spot sales, whilst further east or south in Europe they still retain substantial oil linkage.

Nevertheless, it is safe to say, that although there are still purely oil-indexed contracts, pricing is becoming more complex. The traditional purely oil-indexed contract model has gradually diminished across much of Europe in favor of more hub indexation or a mix of the two. The dominant form of pricing in Europe is currently a hybrid system, with some form of oil indexation, but put into a pricing corridor. Pricing corridors are designed so that contract prices track European hub prices up and down, stopping them from spilling beyond the hub price if the oil price rises or falls too far.

The classical form of indexation to oil products usually also includes a weighting of each different kind of oil product to reflect the weight of each of the Buyer's consumption sectors (home/office heating, heavy industrial use, etc.).

Parties also need to agree which oil reference price to use. The most common one in Asian trade has been the Japanese Customs Clearing price which is the average price recorded by Japan for its slate of oil imports.

In 2017, the share of oil price escalation was 19.5% of global gas consumption.

In oil linked contracts, a time lag is built into the indexation formula, which can range between 3 to 9 months, to allow for the gathering of the relevant data.

When a gas price is said to be based on oil parity, the price of gas is 17.24% of the price of Brent, on an equivalent energy basis.

Japan Crude Cocktail (JCC)

The Japan Crude Cocktail price, or the average price for customs-cleared crude oil imports, is used as the benchmark for LNG prices for Japanese Buyers. The Japan Crude Cocktail is an average of crude oils imported into Japan and can be

the average of a dozen different crude oils imported, all with different contracts, formulae and linkages, including crude oil prices and spot cargo deliveries. So, although the JCC price linkage mechanism is not a pure Brent linkage, one can notice that there is a direct, lagged relationship to Brent. The data provided also includes a dollar yen exchange rate.

The original rationale for the contract structure in Japan was that LNG was seeking to substitute for oil in both heating and in power generation. Japan was actually burning crude oil in power generation, so the use of a crude reference price made sense as a proxy for the value of LNG. It should be noted, however, that the formula does not have the sophistication of European pipeline contracts, where the reference price is broken down between fuel oil and heating oil and given respective weightings in order to mimic as closely as possible the final value of natural gas in each market segment.

Challenges of oil indexation

In the early days of the gas industry, linking the price of natural gas to that of oil was an effective way to incentivize investments in major gas projects, while helping consumers to manage the price risk of switching away from oil. The price was determined based on the replacement value of the gas, which in practice meant the price of oil, as the main competing fuel. In Europe, much of this was introduced in the early 1960s, to underpin the development of the super-giant Groningen gas field in the Netherlands.

Gas markets look different today: the primary competitor for gas is often now coal on one end of the spectrum and renewables on the other. Thus, oil and gas markets have diverged in recent years, and therefore linking the price of the one to the other calls into question the most important function of prices, namely, signaling scarcity and triggering timely investment where and when it is needed. Although it cannot be taken for granted that gas-to-gas competition – or hub-pricing - generally delivers lower prices than oil-indexation, it certainly delivers “correct” prices in the sense that they reflect the value of gas, not that of another product.

If oil prices rise faster than gas prices, this would put a strain on the system, as those Buyers locked into oil-indexed gas contracts face economic hardship and seek ways to benefit from cheaper spot gas. If on the other hand, oil prices were to be low for longer, then oil-indexed gas prices would suggest ample availability of gas at a time when new investments in gas might in fact be needed.

Well-functioning gas markets, therefore, require a price that reacts to changes in the supply-demand balance for gas (which is not the case if prices follow

fluctuations in the oil market). As stated, however, a competitive and/or cheaper priced gas market does not follow automatically from a switch in pricing mechanism.

Alternatives to oil price indexation

Other forms of indexation than oil indexation are perfectly possible in gas pricing in GSPAs. Such alternatives can be more appropriate in some cases, notably when the customers' final market is not connected in any way with the oil business: fertilizer manufacturers sometimes negotiate price indexation that include an element of the price of ammonia in global commodity markets; electricity companies negotiate tolling arrangements sometimes where the gas price is wholly or partly linked to the price of electricity, so that their gas price moves back-to-back with their PPA.

This is usually only possible, however, where electricity itself is sold on a traded market, or where there is a long term-PPA with a Buyer that is not itself subject to price controls by a government or regulator. Failing this, as we saw in the case of Israel, where the antitrust authority and the electricity authority intervened, it led to a distortion of the prices and an unstable gas market.

The independence of the price from influence by one of the parties to the contract, and from the host government of either of the parties, remains a central principle in gas contracts.

US LNG exports pricing formula

Upon the start of LNG exports from the US in February 2016, new pricing formulae were established for these volumes of gas. These include primarily – but not exclusively – prices based on the Henry Hub price and on a tolling model for the liquefaction, as follows:

- Henry-Hub linked GSPAs:
 - Cheniere Model - This is based generally on 115% of Henry Hub price plus a liquefaction charge. The liquefaction charge varies between about \$2.25-\$3.50/MMBtu, depending on what has been negotiated. The Buyer commits and pays the liquefaction charge, regardless of whether it lifts the LNG cargo or not. This fee covers the project company's facilities and fixed cost. The gas fee, on the other hand, is only payable based on the volume of gas liquefied. The gas is sold on an FOB basis. With Cheniere's two export projects, Sabine Pass and

Corpus Christi, Cheniere supplies the feedgas for its long-term customers.

- Cove Point Model - Under this model, Cove Point liquefies the gas, although it does not take title of or market the LNG. Rather again it is the off-taker/Buyer that sources the gas, is responsible for delivering it to the liquefaction terminal and offtake the LNG from the terminal to its destination⁵². For Cove Point and the subsequent Cameron and Freeport LNG projects, each of the tolling customers are responsible for their own feedgas.
- Platts Spot indexation - This is based on the Platts spot indexation. On the 16th June 2018, Platts launched its Gulf Coast Marker (GCM), a price assessment reflecting the daily export value of LNG traded free on board (FOB) from the US Gulf Coast. According to Platts, “The Platts GCM reflects bids, offers and transactions on an FOB US basis, normalized to the US Gulf Coast, and expressed in US\$ per British thermal units (MMBtu)⁵³.

This is published each business day, reflecting the close of Asian Markets; it reflects both lean and rich gas and is based on standard loading cargoes of 135,000-175,000 cu m, and represents the average of the two half-month cycles which represents the first full month⁵⁴.

Other formulae for gas exporting from the US include:

- TTF linked gas price - Cheniere also has a marketing agreement with EDF to supply DES cargoes linked to the TTF Dutch Hub price.
- JKM linked gas price - Tellurian signed an MOU with trading giant Vitol for a 15-year contract, for the Driftwood project, with prices linked to Platts’ Japan Korea Marker (JKM). In addition, Tellurian’s Driftwood project stands out for being a unique model in the US where it not only wants to build and own a terminal, but to produce its own gas, build pipelines and sell cargoes to the global LNG market. In this case, however, many believe that general lack of confidence in the JKM as a benchmark for long-term contracts

⁵² S&P Global Platts, LNG Prices & Pricing Mechanisms, Chris Pederson, North American LNG Pricing Analyst, 6th February 2017.

⁵³<https://www.spglobal.com/platts/en/our-methodology/price-assessments/natural-gas/platts-gulf-coast-marker-gcm-lng-price-assessment>

⁵⁴ S&P Global Platts, LNG Prices & Pricing Mechanisms, Chris Pederson, North American LNG Pricing Analyst, 6th February 2017.

restricts it to spot and short-term deals, despite exponential growth in JKM derivatives trading.

Indeed, Tellurian's senior vice-president for LNG trading and marketing Tarek Souki told Petroleum Economist that the gas from this project would be "CIF linked but is an FOB contract. We account for a shipping differential, it is JKM minus a formula we have agreed. They backed-to-back with Tellurian Marketing on that, not with Driftwood directly. I do not think the banks are ready yet to go and finance a whole project on what the Asian price is going to be over the long term. I know one day it will get there, or the Gulf Coast marker will reflect what the best destination price is - it does already - but with greater liquidity will reflect even better what the rest of the market is doing - and the banks will get comfortable with that, but we are still some ways off that."⁵⁵

- Brent linked indexation – NextDecade announced in April 2019 the signature of the first US LNG contract linked to Brent, signed with Royal Dutch Shell⁵⁶.
- Risk sharing - Another alternative is the risk-sharing model, where Buyers of export volumes would look to get exposure to low US wellhead prices in exchange for giving US producers a greater ability to benefit from higher international prices.⁵⁷

Nearly 80% of US LNG export volumes for projects in operation and currently under constructed have been contracted on pricing terms directly linked to the Henry Hub price, or under a hybrid pricing mechanism with links to Henry Hub.

Oil linkage is thought to be popular with certain LNG buyers with end-user demand portfolios, for the sake of familiarity if nothing else. Going forward, US LNG export contracts may be "an amalgam, a formulaic price mixing gas and oil"⁵⁸.

Inflation linkage

Older models of gas prices in Europe included indexation to general price indices – linking the price of natural gas to a measure of power generation inflation or to

⁵⁵ Petroleum Economist, Tellurian takes flexible approach, 27th March 2019.

⁵⁶ Platts, 4.4.2019

⁵⁷ World Gas Intelligence, 30 January 2019

⁵⁸ World Gas Intelligence, Oil Indexation Still Exerts Strong Grip on Asian LNG, 27 February 2019

the Consumer Price Index (CPI). Some contracts with pure inflation indices survived in Britain until the 1980s, whilst those linked to power generation inflation were mostly phased out by the 1990s.

While both sides of a gas contract may see attractions in an inflation based indexation, CPI indexations are in fact now relatively rare in gas contracts. This is because CPI is of questionable relevance and will be a poor proxy for the inflation either of upstream oil and gas costs, or for the downstream power generation costs. In the past, oil and gas costs, as measured by the IHS upstream capital cost index, increased far more than regular inflation in most developed economies.

CPI might be more appealing from the market perspective where gas is sold directly to a large number of residential and potentially even commercial consumers, whose budget is determined by their disposable income.

There are also fixed contracts with fixed prices, some of which are linked to the prompt, others which are linked to month-ahead prices."⁵⁹

Gas-on-gas competition

Gas-on gas-competition is described by IGU as the price which is “determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK), or the largest European hub today TTF in Holland [...]”.

Not all gas is bought and sold on a short-term fixed price basis and there will be longer term contracts, but these will use gas price indices to determine the monthly price, rather than competing fuel indices.

Also included in this category are any spot LNG cargoes, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple Buyers and Sellers.

Over the last dozen years, the share of gas-on-gas competition in the world has increased. Important prerequisites for gas-to-gas competition include the existence

⁵⁹ Flame Conference in Amsterdam in May 2018, Sergei Komlev, the head of pricing at Gazprom Export, told S&P Global Platts

of various sources of gas supply that can compete in a market and the possibility for Buyers to re-sell and ship the gas within their regional market to other Buyers.

The IGU 2018 survey shows that gas-on-gas competition in 2017 had the largest share in the world gas market. Out of a total world consumption of some 3,740 bcm, gas on-gas-competition had a 46% share in 2017, totaling over 1,700 bcm, dominated by North America at 950 bcm, followed by Europe at 380 bcm and the Former Soviet Union at around 190 bcm. In all, gas-on-gas competition can now be found in 54 countries, in one form or another, and in all regions of the world.

Insofar as the Asia LNG market is concerned, despite perennial talk of pushing oil indexation out of this market in favor of gas-on-gas pricing, lack of a credible alternative means oil won't be disappearing any time soon. Even linkage to US hub prices has proven to be a mixed blessing in Asia.

When oil was above \$100/bbl from 2011-13, Buyers seized on the chance to buy US LNG, which was cheaper than oil-indexed LNG and gave them exposure to Henry Hub for the first time. With the Brent forward curve at \$60-\$61/bbl in 2022-23, supporting a stable lower-for-longer outlook, and an easing in slopes to around 12%, Buyers are likely more open to oil-indexed deals again. Buyers have flip-flopped between oil and hub indexation, depending on oil prices and price outlooks. For now, it seems that Brent is replacing the once ubiquitous Japan Crude Cocktail as the preferred marker as it is easy to hedge⁶⁰."

Buyers risk racking up big losses if they get their bets on oil and gas prices wrong over the next 20 years, so developing a portfolio of price indices is key. Decisions on the mix will be based on individual circumstances. "To mitigate the residual price index risk, whereby it cannot be covered by internal natural hedges available to individual buyers, an effective way is to diversify the mix roughly in line with the overall LNG market at any point of time, to the extent practicable. Right now, a good mix could be a 15%-20% share of Henry Hub pricing, 20%-25% spot and the rest oil indexation. Assuming global LNG supply grows to 380 million tons/yr in 2020 and output from US first-wave projects is price-linked to Henry Hub, almost 18% would be linked to the US gas hub"⁶¹.

⁶⁰ World Gas Intelligence, 27.2.2019, Oil Indexation still exerts strong grip on Asian LNG

⁶¹ World Gas Intelligence, 23.1.2019, Shift to sellers' market heralds LNG contract rethink

6.5 Floors, ceilings and price stability

In a GSPA, the base price defines what price the escalation is applied to and the actual or effective price may be above or below that base price depending on how the escalation factors move.

A floor price is a level below which the price will not be allowed to go regardless of whether escalation would normally have taken it below that floor level, and vice versa for the ceiling price. It thus stems that normally, in GSPA negotiations, Sellers want a 'floor price' while Buyers want a 'ceiling price'.

However, it is relatively rare for a GSPA to have floors and ceiling prices. The reason for this is that floors and ceilings are really distortions of the pure value, and although they give the Seller some protection during the bad times, they don't necessarily provide this same level of protection in bad times to the Buyer and it may make the contract impossible for the Buyer to sign. Floors are especially impossible in an LNG contract, as the LNG market is globally competitive.

However, if the GSPA does have floors and ceilings, then the floor and ceiling or the price as a whole, could be driven by an oil price + CPI over the years, or part of the floor price could be linked to the CPI. For example, if the Seller wants to protect itself against potentially increasing operating costs over the years, and if Seller's operating costs are 20% of its total costs, then Seller could ask to have 20% of the floor price linked to the CPI. Although if Seller's operating costs are well-managed, the costs should not necessarily increase in time.

On the other hand, after several years within the term of the contract, the Sellers will have recuperated their CAPEX and financing expenses, so it becomes easier for them to sell the gas, even if the price has not increased over the years.

And yet, another scenario could be one of a phased development of the Seller's gas field. Under such circumstances, years later the Seller may need to sell new gas at the former higher gas price and may not be able to live with a decreasing and/or non-inflation linked price. Under these circumstances, the pricing formula in the GSPA has to somehow protect the Seller for changing market conditions and by some means reflect its future costs.

Floor prices can also be floating, namely they can change based on certain circumstances. See example here below:

Example of floating floor price: Tamar GSPA in Israel with IPPs

Notwithstanding the provisions of Article [...], the Contract Price in US Dollars calculated based on the Representative Rate as at the date of the Monthly Statement shall not be less than five US Dollars and twenty Cents (US\$5.20) per MMBTU (the “**Floor Price**”) provided however that:

- A. If at any time during the Contract Period the Contract Price... is less than US\$5.20 for a period of 6 consecutive Months, then the Floor Price immediately following such six-month period shall be reduced to US\$5.00; and
- B. If at any time following: (i) the reduction of the Floor Price under Article ‘A’ above; or (ii) the increase of the Floor Price under Article ‘C’ below; the Contract Price calculated in accordance with the formula is less than US\$5.00 for a period of 6 consecutive Months, then the Floor Price immediately following such six-month period shall be reduced to US\$4.70.
- C. If at any time following the reduction of the Floor Price as per the above article, the Contract Price calculated in accordance with the formula described is equal to or more than US\$5.00 for a period of 6 consecutive Months, then the Floor Price immediately following such 6-month period shall be increased to US\$5.00.

6.6 Price re-openers / Price reviews

Most gas sales contracts recognize explicitly that indexation may not always, and in all circumstances, succeed in keeping the commercial balance that the parties originally intended when they agreed the price and terms. They therefore include other critical elements of price flexibility such as price reviews or reopeners.

These are becoming more common place in long-term contracts, although certainly not all gas sales’ contracts include such reviews. They are less common in many of the old legacy contracts.

Price reviews are always tedious and sometimes acrimonious, and the outcome can affect project sponsors’ ability to repay loans.

Lenders’ main concern is whether project cash flows can cover debt repayment at the agreed price. According to World Gas Intelligence: “While a price review can result in a lower price for sellers, lenders are pragmatic and recognize that the potential volatility in Brent — or another price marker — is likely to have a

much greater impact on cash flow than the potential variation arising from a price review.”⁶²

When prices are low, then there is little benefit for Buyers to agree to include a price review, and during such times (e.g. Q1 2019) Buyers try to lock themselves into low prices for as long as possible, and are increasingly looking to extend the interval between price reviews, typically five years, or even eliminate them as contract tenures shrink from 20-25 years to 10-20 years.

When there are reviews, it is often just as much the Seller that insist on having them included in the contract. Indeed, not all Sellers are willing to forgo reviews, and for Sellers that insist on them may face Buyers that will demand to have the option to cancel the contract if negotiations cannot reach an agreement on the date of the review. Again, when prices are low, Sellers are willing to agree for only a five-year or seven-year contract without any reviews, but if it is 15 or 20 years, there will be at least one price review during the term. Sellers are still keen to get the chance to review prices when the market recovers.

Sometimes, there are automatic provisions for reopening price discussions every 3 years; other contracts may have their first review a number of years down the line.

In addition, it is becoming more common in the formulation of new gas contracts, for each party to have the right to request exceptional reopening of the gas price, if it feels that circumstances have changed so profoundly that the commercial balance of the contract has changed. Each party may have the right to do this, namely, to play the ‘joker card’ as it is colloquially known on one or two occasions in each 10-year contract. The circumstances under which either party can claim a renegotiation are tightly defined in most contracts and a claim for reopening the price must be carefully justified and reasoned. A typical wording is as follows:

If the economic circumstances in the market of the Buyer, which are beyond the control of the parties, should change significantly compared to what is reflected in the price provisions of the contract, then each party shall be entitled to an adjustment of the price provisions, reflecting such changes, in particular the value of natural gas in the end-user market of the Buyer, as such value can be

⁶² World Gas Intelligence - Shift to sellers’ market heralds LNG contract rethink (Clara Tan), 23.1.2019

obtained by a prudent and efficient marketer of gas. If the parties cannot agree on a price within this framework, then the contract will specify terms for arbitration.

Providing for periodic agreed upon price reviews in a long-term supply contract balances two competing concerns:

- It allows the price to be adjusted to maintain the parties original commercial position over the lifetime of the contract, because circumstances may change; and
- It avoids having too frequent reviews, which could have the adverse effect of increasing contractual uncertainty.

Like other long-term gas supply contracts, LNG GSPAs often include a price review or reopener provision. This will generally provide for periodic dates when either party may request a price revision or adjustment when there has been a change of circumstances meeting certain requirements in a defined market within a defined period of time ('review period').

There are different approaches to how a price review is triggered. For example, whilst it is less common in LNG GSPAs, the parties may include a provision providing for automatic price adjustments at regular intervals, based on the levels of published fuel prices or tax rates. More commonly, many LNG contracts provide that a party may request a price revision where certain criteria have been established, such as a substantial and unforeseen change in circumstances that was beyond the parties control. The price review provision will usually define the market in which the change must take place (e.g., within a specified geographic market, the Buyer's end-user market in a certain geographic area, the Buyer's market more generally, specific segments of a market). As liquid traded gas markets have developed, a number of Buyers have initiated price review requests, seeking to introduce gas hub pricing into the price formulae in their LNG contracts (usually in place of, or in addition to, price formulae linked to oil products)⁶³.

⁶³ <https://globalarbitrationreview.com/chapter/1142624/destination-restrictions-and-diversion-provisions-in-lng-sale-and-purchase-agreements>

6.7 Gas hub and hub pricing

What is a hub?

A hub is a geographical location where multiple participants trade energy. In essence a hub facilitates gas wholesale trading as a marketplace and defines a hub gas price market.

Creation of a gas hub requires an independent and neutral player; the availability of ample gas supplies and liquidity of products (short and medium term), and the legal and regulatory framework together with the facilitation of the wholesale trading rules and procedure and a network operator to facilitate the market place for all market participants to book, allocate and transport capacity along the gas network. The network operator needs to be unbundled, so it can guarantee independent management and access for market participants. This also requires transparent third-party access and transparent rules for capacity allocation, congestion management and balancing. The regulator and the competition authority have to play a strong role to promote competitive supplies and a diversity of suppliers, sufficient network capacity and flexible trading products.

Where there is a well-developed meshed network, or where there are multiple interconnecting pipelines belonging to different operators, then traded hubs can develop.

For a hub to exist, a certain number of conditions need to prevail, some of which include: a large number of Buyers and Sellers; deregulated gas prices (price liquidity at the hub increases to the point that Price Reporting Entities' (PRE) reported prices at the hub become a reliable indicator of market balance and enable parties to cite these for future pricing in long-term contracts; a liquid forward price curve (parties trade large numbers of futures contracts for deliveries many months out, providing future price discovery and a means of managing price risk and future commitments).

Secondary gas market

A secondary gas market typically develops alongside the main market where companies trade volumes under bilateral contracts.

In Europe, there are underlying long-term delivered contracts based on price indexation of some description that has been agreed. Some of the volumes in these long-term contracts may not be fully sold, which leaves a surplus of gas on the market place and thus the requirement that these volumes be sold on the spot market and it is these gas volumes that are then sold as part of the hub. A lot of

this is just trading with the gas sometimes changing hands dozens of times before it is finally consumed (churn rates⁶⁴).

The purpose of a secondary gas market is to allow companies to 'top up' should consumers need more gas. For example, a company (Buyer) signs a supply contract with a Seller for 100 million cubic metres (mcm)/year. The Buyer will be selling the gas to an end-consumer. This means that the Buyer of gas will ask the Seller to supply the gas based on the daily needs of Buyer's end-consumers. Let's say Buyer forecast that the consumer's daily demand would be around 274,000 cubic metres/day (100,000,000/365). However, if for some reason the consumer sees a sudden increase in demand, it would tell his supplier (in this case our Buyer of gas) to supply more gas. That additional gas will come from a secondary gas market where our Buyer would contact other companies (either producers or suppliers of gas like itself) to ask whether they have any spare volumes to sell.

In their initial stages of development, secondary gas markets are purely for the physical delivery of gas. Namely, in the early stages, companies typically do not buy gas for speculative purposes, but rather only for the physical delivery of the commodity. A good case in point of a country that recently developed a secondary market for gas is Turkey. Most of the gas there was contracted under long-term contracts (typically 1 year or longer). If a need arose for additional gas, companies would be buying from the secondary gas market for immediate delivery.

Over time, and if governments decide to create the necessary conditions to open up their market, these secondary markets can become more sophisticated and develop into long-term forward markets, similar to those in Western Europe or the US

Once a more developed secondary market opens up, it means that the format of trading changes, in the following manner:

- Companies will not be trading bilaterally and deliver the gas at any entry point in the system, instead trading will happen on a virtual trading point (VTP) agreed by all counterparties.
- The pool of market participants will grow to include not just traditional utilities/producers, but also banks, hedge funds, municipalities etc.

⁶⁴ The churn ratio measures how often a gas molecule is traded. The OIES considers a hub mature when total trade volumes are at least 10 times greater than physically traded volumes - parameters met only by the TTF and NBP.

- Trading will happen not just for physical delivery, but also for speculative purposes. This is why quantities of gas can change hands 10-15 times (churn rate) before they are actually supplied to an end-consumer.
- There will be just one reference price that reflects supply and demand rather than a multitude of prices set by bilateral contracts and which are typically indexed to oil, coal, electricity or as in Israel's case to the US CPI⁶⁵.

Hub pricing

The spot/hub price should not be confused with the average price in the market. Rather it is a benchmark that is often used to see whether other contracts are higher or lower than the hub price.

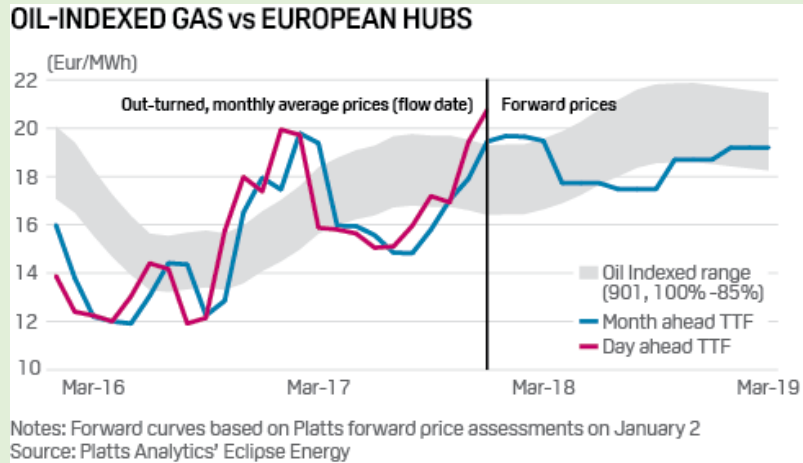
For example, Russian gas during certain months of the year can be higher than the hub prices and lower during other times of the same year. Russian gas has been competitive with European hub pricing over the past few years, given the low oil price environment during this period, combined with Gazprom's recent pricing structure leaning toward more hub indexation or hybrid pricing, to meet demands made by European Buyers. Whilst at other times, high Russian oil-indexed long-term natural gas prices causes European gas hubs to rise as a deficit can occur as a result.

Gazprom's contracts have, usually been linked to oil prices, although the company's pricing strategy range from hub- to oil-indexation with a variety of hybrid options in between, agreed on a case-by-case basis.

The hub prices are guided by the prices of alternative fuels and oil. So, although everything is connected, they are working in different environments.

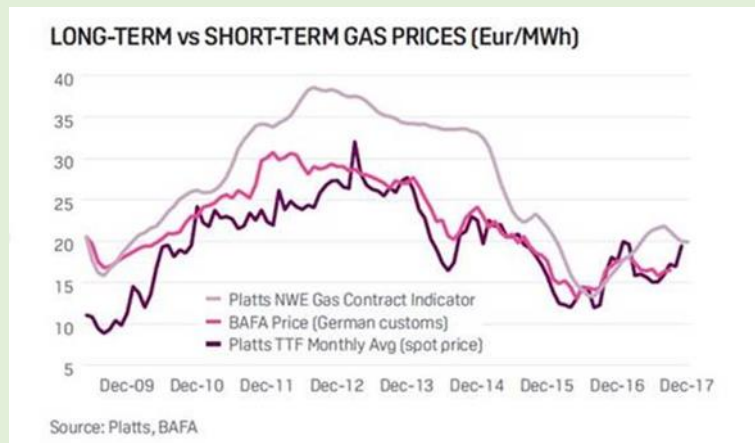
⁶⁵ Dr. Aura Sabadus, via email

Example: oil indexed gas vs. European hub price



One can see from the example above dated 2.2.2018, how the TTF month-ahead prices are sometimes, below, within or above the oil-index price range during different periods of the year.

In the example below, one can see how the spot/hub price can be lower than the long-term contract price.



The hub prices are important because at the end of the day the hub is the market of last resort for suppliers. If for example, a supplier has a cargo of LNG in the middle of the Atlantic for which he has no guaranteed Buyer for it, and if Henry Hub price is at \$3/MMBtu and NBP is at \$5/MMBtu, and if the cost to ship the cargo to either location would be the same, the supplier would then send this cargo to the UK.

Gas Buyers in Europe cannot survive only on the short-term market because although this is fine when the price is low, when the price is high it can skyrocket, so Buyers need to hedge their portfolio with their long-term contracts with a certain and assured price and then any flexibility they have in their long-term contracts ($\pm 30\%$ below/above their ACQ) they can then try to optimize on the short-term market.

LNG-based hubs

LNG contract prices are generally negotiated in relation to a slope, which captures the link in percentage terms between the oil price in dollars a barrel and the gas price in dollars per MMBtu. On an energy-equivalent basis, the gas price would be about 17.24% of the oil price, but in order to ensure the competitiveness of LNG, the slope is normally negotiated within a 13%-16% range, depending on the market conditions at the time and the bargaining positions of Buyers and Sellers. A standard assumption is that the average slope is 14.85% (plus a fixed element of about \$0.5 per MMBtu), meaning that when oil prices were at their peak in 2014, the LNG price would be just over \$17.50 /MMBtu, while at \$65 it would be closer to \$10/MMBtu.

Most LNG in Asia, which accounts for 70% of global demand, is price-linked to crude at slopes ranging from 12%-15.5%, depending on factors like when the contract was signed, its duration, Buyer/Seller risks and whether deliveries are weighted toward certain times of the year. This was especially the case before US LNG arrived on the scene, when Asian buyers were contending with high oil slopes ranging from 13%-15% on Australian projects under contracts running into the 2030s. However, with alternatives to crude oil indexation, some of the slopes started to fall and just as importantly “the ratio of spot LNG prices relative to crude oil prices - or oil slope – fell as low as 6.71% in March for May 2019 delivery, the lowest in nearly nine years”⁶⁶. Thus, robust Dated Brent prices created a significant disparity between long-term contract prices - the majority of which are linked to crude oil prices - and spot prices. Furthermore, according to Platts, the April-delivery spread as a percentage of term Dated Brent contracts, was about 28.66%, almost an eight-year high. The spread, as a percentage of term Dated Brent contract, indicates the percentage saving for a Buyer to procure on a JKM-basis instead of Dated Brent prices⁶⁷.

⁶⁶ Platts, 25.3.2019, Platts (Srijan Kanoi, Kenneth Foo) - LNG, oil spot price divergence stokes uncertainty over forward deals, hedging

⁶⁷ Ibid

With the Brent forward curve at \$60-\$61/bbl in 2022-23, supporting a stable lower-for-longer outlook, and an easing in slopes to an equilibrium of around 12%, Buyers are once again more likely open to oil-indexed deals.

More recently there has been a shift towards use of a hub based indexation in LNG. LNG-based hubs present a number of challenges compared to pipeline-based hubs.

Pipeline hubs rely on more or less continuous flows of natural gas, daily scheduling of receipts and deliveries, homogeneity of product, standardized natural gas specifications, uniform transportation and contracting rules, and diligent regulatory oversight.

In contrast, LNG price discovery presents a number of challenges compared to the pipeline-based model of market hub and price index development. LNG shipments can be large and difficult to store, there can be significant time between contracting and delivery, and cargoes can differ in LNG specifications. An LNG market hub needs to also include port facilities, LNG storage, regasification or liquefaction capacity and pipelines interconnected with the markets.

As the global LNG market continues to evolve and mature, reliable pricing indices and market hubs in Asian countries will fundamentally transform the global LNG market into a more efficient, integrated, and transparent market.

US Hub

Natural gas is priced and traded at different locations throughout the US. These locations, referred to as market hubs, exist across the country and are located at the intersection of major pipeline systems. There are over 30 major market hubs in the US, the principle one of which is known as the Henry Hub, located in Louisiana. The futures contracts that are traded on the NYMEX are Henry Hub contracts, meaning they reflect the price of natural gas for physical delivery at this hub. The price at which natural gas trades differs across the major hubs, depending on the supply and demand for natural gas at that particular point. The difference between the Henry Hub price and another hub is called the location differential.

6.8 Future of gas pricing

Gas pricing formulae are changing and are becoming more varied. The changes of how markets have evolved over the years are due to a number of factors: more spot imports, more LNG, ending/renewal of GSPAs to include a proportion of

hub/spot price indexation or even 100% hub price indexation, renegotiations leading to the introduction of a hybrid price formula with oil indexation partly maintained but within a price corridor set by hub prices.

Although for years, long-term gas contracts, with strict destination clauses and oil linked prices were needed to enable gas companies to make the huge upfront investment needed to bring the gas to the market, this is changing. As the example of North America makes it clear, a well-functioning gas market, with prices determined by competition between various sources of gas, can offer sufficient incentive for large-scale investments, although this market is experiencing a certain reversal in fortunes as the second wave of US LNG took potentially longer to reach FID.

Most Asian gas markets are still dominated by oil pricing. Some Asian Buyers worry about losing money if they get price forecasts wrong and feel there is no downside in taking an oil-linked contract, but there is plenty of downside if future hub prices relative to oil end up being significantly higher than expected⁶⁸. For them a bet on hub pricing is still a big risk.

Nevertheless, it is abundantly clear that oil indexation is on the decent. As expressed by Woodside Energy CEO Peter Coleman at the WGC Conference in June 2018: "the time has come or is coming very fast where you're not going to be able to link oil and gas together anymore", adding that "in my view the sooner they delink, the better... LNG should be able to stand on its own as its own commodity traded in the marketplace and be competing on its own."

The flexibility that independently priced LNG may afford is also in keeping with what some major gas Buyers are looking for. According to Seung-II Cheong, President and CEO of Korea Gas: "The dynamics in the LNG market are changing, and from the buy-side, diversified price indices and more options are key developments", he said⁶⁹.

7. CONTRACT EVOLUTION

GSPAs have evolved substantially over time, depending mainly on the gas market structure. We may be entering a "hybrid period" in which various forms of supply arrangements – long-term and short-term, large and small, oil-indexed, hub-based,

⁶⁸ Bernstein Research analyst Neil Beveridge

⁶⁹ ICIS European Gas Market 31 May 2018

hybrid and spot – coexist and compete with each other - reflecting the different needs of Buyers and Sellers alike.

Gas supply portfolios of gas Buyers in the future may include a mix of spot purchases and short, medium and long-term contracts, leaving the leading role for long-term contracts as a tool for investment certainty. Although long-term contracts could still have a role to play, especially in Southeast Asia where new entrants such as Pakistan are keen to sign long-term oil linked and even destination specific LNG contracts, European players are no longer willing to take the risks such contracts entail. The gas market in general and the LNG market in particular is fast transitioning into a true commodity market and long-term contracts will become less the norm in the future.

With LNG a commodity 'in the making' there could still be a need for long-term contracts to help finance new LNG projects, but many Buyers are now saying that 10-year contracts is the longest horizon they can risk manage, and that optionality is a key consideration in contract negotiations. LNG players will have to come up with a new business model as many markets have become sufficiently liquid that Buyers do not need, and there is no incentive for them, to enter into long-term contracts, that would underpin the investment, unless it is a large Buyer or is facing logistical issues.

In the long term the direction for interstate trade seems clear: a marked shift towards spot trade, smaller volume contracts and their shorter duration together with a distinct move away from destination clauses and oil-price indexation.

On the gas pricing front, new models are being offered, such as the NextDecade LNG model in the US, which is the first US-based project to offer Brent-linked supply of natural gas, but is also exploring a plethora of other options such as TTF or JKM netback pricing, as well as Henry Hub indexation and alternative US index options.

As more players entered the LNG market, the average difference between spot market prices and netback prices declined. As a result, the spot market prices became less variable, which consequently eroded the advantages of long-term contracts in allowing higher project leverage. At the same time, the changes influenced the use of contracts in spot markets, increasing market liquidity. An increased desire to take advantage of spot and short-term arbitrage opportunities also raised the demand for greater flexibility in long-term contracts.

8. SUMMARY

Below are some bullet points listing and summarizing some of the main issues that represent Sellers' and Buyers' interests, that are sought by the parties of gas contracts.

For the Sellers – What Sellers want:

- Credit worthy anchor Buyer
- Maximum possible prices based on market, competition, economic efficiency, rate of return and regulations
- Maximum sales' revenues – IOCs (independent and international oil companies) need to know they will be able to monetize their investment. Once they have achieved their return-on-investment, security of payment can suffice
- High Take or Pay, and minimum swing
- Optimization of costs
- Access to resources - need to understand what access they have to the resources (e.g. the US has total open access, while Mexico prevents access to IOCs)
- Access to the markets - security of demand and long-term contracts
- Stable and equitable fiscal regime
- Control over all or most elements of the chain, especially production & liquefaction, and spare capacity through the supply chain, enabling better performance and lower costs
- More pre-FID planning, so that more contracts are 'signed and sealed' pre-sanction, often with preferred partners versus putting everything out to bid, although this has not been the case with two prominent LNG FIDs taken in North American by major players in 2018.
- More tie-backs and brownfield projects that use existing infrastructure, less greenfield.⁷⁰

For the Buyers – What Buyers want

- Buyers have on a whole, greater options than Sellers, as they can pick which projects to sign a long-term GSPA with. Although this is not universally correct, as some markets are characterized by monopoly pipeline suppliers.

⁷⁰ Last 3 points were stated recently by Wood Mackenzie; <https://www.woodmac.com/press-releases/global-upstream-project-delivery-is--finally-hitting-the-mark/>

Nevertheless, LNG trade is growing and providing greater optionality to all Buyers

- Important for Buyers to have a clear understanding of their market/project, so they know what they can commit to (volume, price)
- Proof that Sellers have the financial and technical capability to deliver; the available infrastructure and government support
- Reliable supplies and on-time deliveries; compensation for Sellers' supply failure
- Prices competitive with other fuels over time; GSPA to be in line with PPA (if power project)
- Low TOP (if availability of liquid market) and maximum swing
- Gas quality is vital
- Most important for the Buyer is security of supply, including timely delivery. Project economics and developers' flexibility are typically key to determining how attractive Buyers find liquefaction schemes. Buyers want to see that the Sellers can provide offtake flexibility (destination flexibility, delivery timing, and interim supplies). Security, stability and reliability of gas supply, which at some point is more vital for the Buyer, than even the price. Thus, Sellers can often charge a premium if they are an existing supplier with a track record (e.g. Qatar compared to new projects in the US, Russia and Mozambique). Buyers need a comfortable delta between oil-linked LNG and US LNG prices, for US LNG projects, as they have to take pricing risks with Henry Hub
- The Sellers project need to be commercially robust under a variety of economic conditions. If the project is marginal and dangerous, developers may not meet commitments and Buyers will be reluctant to contract from such a project
- Geopolitical risk is a factor
- Price is often of secondary importance (the less secure the supply is, the less the Buyers are willing to pay, if at all)
- Proof that Sellers have the reserves available for 15-20 years and have flexibility to ensure extra capacity if required (e.g. Fukushima incident when Buyers needed fast response from their Sellers).

9. **CONCLUSION**

For many decades, long-term GSPAs have played a considerable role in enabling gas supplies, providing significant benefits to both Sellers and Buyers. Indeed, long-term contracts can be tools to manage and mitigate adverse impacts from short-term price movements and can serve as a 'hedge' on price movements for

Buyers, creating an appropriate investment environment. The degree to which the contract serves the functions depends of course upon the structure of the contract and the pricing terms that are included.

The specific terms and parameters in GSPAs can vary widely from one contract to another, depending on the gas market structure developments, circumstances surrounding the contractual relationship between Buyers and Sellers, the negotiations strength (or skills) of each side, the parties' particular needs or regulatory conditions.

Every party of a GSPA has its own requirements, needs, interests and objectives, normally characterized as multidirectional and not reciprocal. A gas contract defines a clear split of risks and responsibilities between the Buyers and the Sellers.

Remember, this is a negotiation and neither side will win all its arguments and each side needs to be prepared to compromise to reach a settlement. Real contracting is not a perfect world, it is about negotiating, compromising, trade-offs, understanding one's strengths and weaknesses and understanding if one concedes x what y does one get in return; pushing far enough to be safe but not too far that one can never sign the contract.

It must be stressed that all that can be achieved in any GSPA negotiation is to address

later when an event might occur and when the actual individuals involved in the drafting may no longer be involved.

In many circumstances, there are no set rules that can be followed and so one has to urge some caution not to be too prescriptive on some of the issues expressed in this paper or otherwise. The agreed outcome in most GSPAs is reached from negotiations and will depend on a number of issues, including market context, physical properties of the supplying field and/or pipeline infrastructure, local laws, regulations and tax regime, relative strengths of Sellers and Buyers and many more issues.

Readers must thus be sure to add some caveats to the points explained in this document.

Long-Term Gas Contracting

Terms, definitions, pricing
- Theory & practice



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The Institute of Energy for South East Europe (IENE)

The Institute of Energy for South East Europe (IENE) was founded in 2003 by a small group of independent professionals and business executives active in the energy sector of the region. The Institute, which has its headquarters in Athens, Greece, is a non-governmental and non-profit organization. The Institute's prime purpose is to constitute a permanent forum where energy issues can be discussed, analyzed, reformulated and presented to a broader audience, in unbiased, objective and credible terms. This is achieved thanks to the Institute's scientific standing, its managerial rectitude and the transparency of all its operations.

The Institute activities span all forms of energy including from hydrocarbons, solid fuels, electricity, nuclear, renewables to energy efficiency. The Institute is largely funded from its membership which includes both corporate entities and individual energy professionals.

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