NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

Methodology to Approve Maximum Prices of Piped-Gas in South Africa

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Table of Contents

Glossary of Terms and Acronyms

ALSI	All Share Index (of the Johannesburg Stock Exchange)
CIF	Cost Insurance Freight
Distribution	The distribution of bulk gas supplies and the transportation thereof by pipelines with a general operating pressure of more than 2 bar gauge and less than 15 bar gauge or by pipelines with such other operating pressure as the Gas Operator may permit according to criteria prescribed by regulation to points of ultimate consumption or to reticulation systems, or to both points of ultimate consumption and reticulation systems, and any other activity incidental thereto, and "distribute" and "distributing" have corresponding meanings;
Gas Act	Gas Act, 2001 (Act No. 48 of 2001)
GPL	GASPOOL
HH	Henry Hub
JKM	Japan/Korea Marker
JSE	Johannesburg Stock Exchange
K_d	Cost of Debt
K_e	Cost of Equity or Return on Equity
LNG	Liquefied Natural Gas
NBP	National Balancing Point
NCG	NetConnect Germany
NERSA Act	National Energy Regulator of South Africa Act, 2004 (Act No. 40 of 2004)
Gas	All hydrocarbon gases transported by pipeline, including natural gas, artificial gas, hydrogen rich gas, methane rich gas, synthetic gas, coal bed methane gas, liquefied natural gas, compressed natural gas, re-gasified liquefied natural gas, liquefied petroleum gas or any combination thereof
Tariff Guidelines	Guidelines for Monitoring and Approving Piped-Gas Transmission and Storage Tariffs in South Africa, NERSA, 30 March 2017.
Price	The charge for gas to a distributor, reticulator or final customer
Regulations	Piped-Gas Regulations, promulgated in terms of the Gas Act, 2001 (Act No. 48 of 2001), gazette No 29792, 20 April 2007

Reticulation	The division of bulk gas supplies and the transportation of bulk gas by pipelines with a general operating pressure of no more than 2 bar gauge to points of ultimate consumption, and any other activity incidental thereto, and “reticulate” and “reticulating” have corresponding meanings
RRM	Regulatory Reporting Manuals
Service	Any service relating to the transmission, distribution, storage, trading, liquefaction or re-gasification of gas
Tariff	The charge for gas services to any customer
Trading	The purchase and sale of gas as a commodity by any person and any services associated therewith, excluding the construction and operation of transmission, storage and distribution systems, and “trading services” has a corresponding meaning
Transmission	The bulk transportation of gas by pipeline supplied between a source of supply and a distributor, reticulator, storage company or eligible customer, or any other activity incidental thereto, and “transmit” and “transmitting” have corresponding meanings;
TTF	Title Transfer Facility
VTP	Virtual Trading Point
ZEE	Zeebrugge
ZTP	Zeeburgge Trading Point

1. Introduction

The National Energy Regulator of South Africa ('NERSA' or 'the Energy Regulator') is mandated in terms of the National Energy Regulator Act, 2004 (Act No. 40 of 2004), ('the NERA Act') to regulate the electricity, piped-gas and petroleum pipelines industries in terms of the Electricity Regulation Act, 2006 (Act No. 4 of 2006); the Gas Act, 2001 (Act No. 48 of 2001); and the Petroleum Pipelines Act, 2003 (Act No.60 of 2003) respectively.

This document prescribes the methodology for regulating the maximum prices of piped-gas in the manner prescribed by the Gas Act, 2001("the Gas Act"). It covers the following:

- the legal basis (legislative framework) for regulating maximum prices of piped gas;
- the role of the Energy Regulator in regulating maximum prices of piped gas in South Africa;
- the methodology for the calculation of the maximum prices of piped-gas;
- the methodology for determining the trading costs;
- prescribed sources of data to be used as inputs in the calculation of the maximum prices of piped-gas;
- the manner and content of maximum price applications by licensees or applicants; and
- assessment of maximum price applications by the Energy Regulator.

This document therefore does not reproduce how some elements of the gas transmission and storage tariffs, which are included and passed through in the total price(or charges for gas), are calculated. The methodology for transmission and storage tariff calculation is detailed in the NERSA-approved "Guidelines for Monitoring and Approving Piped-Gas Transmission and Storage Tariffs in South Africa," dated 30 March 2017 ("the Tariff Guidelines").

2. The Legislative framework for regulating maximum prices of piped-gas

2.1. The Gas Act, 2001

NERSA derives its mandate regarding piped-gas maximum prices and gas transmission and storage tariffs from the Gas Act. Amongst various functions set out in section 4 of the Gas Act, paragraph (g) requires NERSA to, as appropriate, in accordance with the Gas Act to, "regulate prices in terms of section 21(1)(p) in the prescribed manner;"

Section 21(1)(p) states that the Energy Regulator, may impose licence conditions within the following framework of requirements and limitations: "maximum prices for distributors, and all classes of consumers must be approved by the Gas Regulator where there is inadequate competition as contemplated in Chapters 2 and 3 of the Competition Act, 1998 (Act No. 89 of 1998)."

In line with this particular requirement, NERSA has developed this Methodology for Approving Maximum Prices for Gas in the Piped-gas Industry. However, the requirement to approve maximum prices and hence to use this methodology is contingent on NERSA determining that "there is inadequate competition as contemplated in Chapters 2 and 3 of the Competition Act, 1998" as stipulated in section 21(1)(p) of the Gas Act. This determination forms part of a separate assessment by NERSA that will be performed on a periodic basis. The current determination of inadequate competition was approved by the Energy Regulator on 27 March 2019.

Complementary to the aforementioned sections 4(g) and 21(1)(p) of the Gas Act, the relevant portions of Regulation 4 of the Piped Gas Regulations dealing with the 'Price Regulation and procedures' are discussed below:

2.2. The Piped-Gas Regulations, April 2007 (GG No 29792 of 20 April 2007)

The maximum price determination principles outlined in this methodology, are further informed by the "Price Regulation Procedures and Principles" prescribed in the Piped-Gas Regulations, promulgated in terms of the Gas Act, 2001, Gazette No 29792, 20 April 2007 ('the Regulations"). The following are pertinent to this methodology.

- Sub-regulation 4 (3) prescribes that the Energy Regulator must when approving the maximum price in accordance with Section 21 (1) (p) of the Act:

    a) be objective, i.e. based on a systematic methodology applicable on a consistent and comparable basis;
    b) be fair;
    c) be non-discriminatory;
    d) be transparent;
    e) be predictable; and
    f) include efficiency incentives.

- Sub-regulation 4 (4) prescribes that the maximum prices referred to in sub-regulation 4 (3) must enable the licensee to:
    a) recover all efficient and prudently incurred investment and operation costs; and

b) make a profit commensurate with risk.

- Sub-regulation 4 (6), then requires that, when gas is sold, the accompanying invoice must itemise the constituent elements of the total price reflected on the invoice, including at least the cost of gas, and transport tariffs and any other charges.

- Sub-regulation 4(7), provides that licensees must provide the Gas Regulator [sic] with sufficient information as required by the Gas Regulator for it to determine maximum prices.

- Sub-regulation (4) (13), provides that, when ownership of gas changes, the price of gas in the new owner's hands refers to the price of gas from the seller plus any tariffs charged by that seller.

These legislative aspects, as prescribed by the Gas Act and the Regulations, are key to defining the scope and nature of the maximum pricing methodology of piped-gas developed by NERSA.

3. Determining maximum prices

3.1 The formula for determining the maximum price of gas

The Dutch's TTF, Britain's NBP and United States' (US) Henry Hub (HH) are currently the only gas trading hubs that are classified as liquid in the world. As such, gas prices in these trading hubs are largely determined by the interplay between supply and demand (gas-on-gas competition). In this regard, the Dutch TTF, Britain's NBP and US' HH are the suitable benchmark hubs against which a gas price that seeks to mimic competition can be linked. The maximum price of piped-gas proposed by an applicant or licensee shall be reviewed for purposes of approval by the Energy Regulator based on the following formula:

Max Price = 0.4 (HH) + 0.5 (TTF) + 0.1 (NBP)

where:

Maximum Price of Gas = Maximum price for gas energy (ZAR/GJ);

Henry Hub (HH) = Twelve months simple average of the Henry Hub monthly prices with a 40% weight in the energy basket;

Transfer Title Facility (TTF) = Twelve months simple average of the TTF monthly prices with a 50% weight in the energy basket;

National Balancing Point (NBP) = Twelve months simple average of the NBP monthly prices with a 10% weight in the energy basket;

The maximum price of gas energy and does not include distribution tariffs, transmission tariffs, storage tariffs and levies. Once the maximum price of gas is arrived at all other charges (tariffs and levies) mentioned above shall be included to arrive at the 'total maximum gas charges' that may be invoiced by a licensee.

3.2 Determining the weights in the formula

The weights used in the maximum price formula is determined using the maturity of the hub in question. The evaluation of the maturity of hubs is based on the following five key elements which will assist in judging whether the criteria of depth, liquidity and transparency of hubs are being met and to what degree.[1]The five key elements are; market participants; traded products; traded volumes; tradability index and churn rates. The churn rate is regarded as the most important measure of a gas hub's commercial success. The churn rate is calculated as the ratio between the volume of all trades in all time-frames executed in a given market and its total demand. Churn rates are regarded as an excellent measure of a hub's real liquidity and maturity. As a result of this, churn rates are used in most commodity and financial markets.

In this regard, the Energy Regulator will take guidance from the churn rate in determining its weight allocation for the identified competitive gas hubs. Below is the proposed weighting of these hubs.

Table 1: Weight allocation for Dutch's TTF, US' Henry Hub and Britain's NBP, 2018

HUB	Churn rate	Share / Weight
TTF	70,9	50%
HH	53,9	40%
NBP	16,9	10%
Total	141,7	100,00%*

**the percentage weight is to the nearest 10.*

[1] See, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/07/European-traded-gas-hubs-a-decade-of-change-Insight-55.pdf, accessed 5 March 2020

Source: NERSA's own compilation, 2020 (from the oxford energy report as per footnote)

3.3 Pass through of costs

The pass through of costs will be used by third party traders and by importers of Liquefied Natural Gas (LNG).

The pricing of traders that purchase gas from other traders will take into account regulation 4(13) of the piped gas regulations. This regulation states that when ownership of gas changes, the price of gas in the new owners hands refers to the price of gas from the seller plus any pass through costs already levied.

Therefore traders will only add a reasonable profit plus their trading costs to the total charges levied by their supplier. The main issue that ought to be established is what such a reasonable profit ought to be. As such NERSA is also proposing the use of a benchmark, being the Japan Korea Marker (JKM) Platts price. This price becomes the maximum price of third party traders that purchase gas from the importers of gas in the current period. The use of such a landed JKM price would be a reasonable way of estimating a reasonable profit for such third party traders. It ought to be noted that in 2018, Asia consumed 75% of the Global LNG that was traded. The predominant method of pricing the LNG have been oil-linked contracts as reflected in the Platts Japan Korea Marker (JKM) price. The LNG suppliers costs represent the marginal costs of the marginal supplier. Hence the JKM is being used as the benchmark for new entrants into the market.

A shipping cost may also be added to this JKM price to arrive at a landed price. Other charges such as regasification tariffs will also be added separately to the price of the gas molecule. Thus a benchmark will be used in conjunction with the cost plus approach as it will be used to establish appropriate profit margins when determining the maximum gas prices of third party traders.

The importer of LNG would also use the JKM price as their maximum price and add their actual shipping and transportation costs as well as eventually add all the other pass through tariffs. The maximum price becomes the JKM. In addition the importer of gas and third party traders will add their trading costs that are calculated as shown in this methodology.

4. Rationality Tests

NERSA will conduct tests to ensure that the maximum price calculated using the formula in 3.1 above meets the requirements of the Gas Act and the Piped Gas Regulations.

4.1. Marginal/actual costs of the gas molecule

NERSA will need to ascertain the traders actual costs of acquiring the gas molecule. For the current importers of gas, they would have to provide NERSA with their actual costs of acquiring the gas molecule from the upstream suppliers. The traders will also be expected to provide the costs incurred in trading the gas molecule using the steps shown in this methodology.

Third party traders that purchase gas from other traders, will need to show the cost of purchasing the gas molecule from their supplier and will also be expected to provide the costs incurred in trading the gas molecule using the steps shown in this methodology.

4.2. Willingness to Pay – The cost of the next supplier of gas to South Africa

The second step entails establishing the Asian market LNG price. The World Bank publishes the LNG natural gas import price inclusive of Cost Insurance Freight (CIF) of Japan meaning that the price includes the liquefaction and transportation cost to Japan. For the purpose of this methodology, this Japanese price will be the upper bounds of the South African natural gas market price as it represents the marginal cost of the marginal supplier. In an immature and supply constrained market such as the South African piped-gas market, it also represents the customer's willingness to pay, which in this case can be considered relative to the next best alternative energy source.[2] In the current market, expectations are that LNG imports are the next source of gas supply that will serve to supplement existing gas supplies, and to eventually replace them when the current source of gas becomes depleted.

The World Bank publication of commodity prices[3] will be used to establish the LNG price that will be a proxy for the cost of the next supplier of gas in South Africa. Section 7 will demonstrate how this will be applied in the determination of the maximum price.

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[2] The cost of the next-best alternative approach, sometimes called the alternative cost"method limits the customers' willingness to pay to the cost of the most likely (i.e. least cost) economically feasible alternative. The method is useful in cases where direct willingness to pay cannot readilty be estimated. See Irrigation Water Cost Recovery in Egypt, Determination of Irrigation Water Costs : an Applied Study, prepared for the USAID mission to Egypt by the Irrigation support project for Asia and the near east, January 1993.

[3] Accessed on 23 March 2020 at https://www.worldbank.org/en/research/commodity-markets

5. Determining the piped-gas trading costs

The maximum price contemplated in the abovementioned Gas Act provisions comprises of both the gas price and the trading costs so as to avoid leaving traders with only an approved:

- underlying gas price without recovery of trading costs since this would have the undesired effect of expecting such licensees to either trade without recovering their trading costs or of encouraging their non-compliance by trading without a trading costs component approved by NERSA through a transparent process; or

- trading costs without a valid underlying price for their gas molecule as this would mean they have no gas price to add those costs onto.

The trading cost (TC) component will however be determined according to a prescribed methodology. To determine the TC element of the maximum price, the Energy Regulator will use the Tariff Guideline to ensure that there is consistency in the decisions taken by the Energy Regulator. The elements that comprise the trading cost differ slightly in treatment from that prescribed in the Tariff Guidelines as provided below.

5.1 Recovery of investment (for fixed assets used in the trading activity)

Investments in limited and trading-specific piped-gas network assets, which are ordinarily required in the normal course of a piped-gas trading business, plus the general plant used for piped-gas trading, will be recovered through the trading cost. The assets that form the trading RAB will be referenced to the Tariff Guidelines. However, the difference with how the trading assets will be treated is that they will not be trended for inflation as articulated in the Tariff Guidelines.

5.2 Recovery of operational costs

All operating costs inclusive of depreciation that are efficient and prudently incurred by the piped-gas trading licensee shall be allowed as a pass-through in the trading cost calculation.

The operating costs to be allowed relate to charges by the trading licensee covering a range of trading services.

These operating costs shall be as grouped and reported to the Energy Regulator in accordance with the RRMs.

5.3 Return on assets for piped-gas trading business

A nominal Weighted Average Cost of Capital (WACC) of the trader will be used to establish the return on assets for the trading business. The WACC will be applied to the sum of Trading RAB of that trader plus Working Capital.

The nominal WACC will be calculated as prescribed in the Appendix of this methodology.

The formula for the trading cost calculation will be as follows:

Allowable Revenue =

(Trading Assets + Working Capital) * WACC + OPEX + TAX <u>+ C</u>

To be billed to customers as a trading cost per Giga Joule as follows: -

Trading Cost in ZAR Gigajoule = Allowable Revenue/Volume.

6. Price adjustment and frequency of price review

The maximum price will be adjusted using the same formula that is used to approve the maximum price.

The maximum gas prices will be reviewed over a period of 12 months using the 12 month weighted average price of the Henry Hub, TTF and NBP prices, as shown in the formula, for the preceding twelve months period. Should licensees seek a different review period based on their commercial agreements, they would request the Energy Regulator to approve a period different from 12 months. However, in all instances, the 12 month weighted average price of the Henry Hub, TTF and NBP prices will be used to review the maximum prices. The use of 12 month average prices will minimise the volatility that may result from the use of a shorter period.

7. Implementation of the methodology

The detailed steps of implementing the methodology are illustrated below. The calculation of a maximum price for January 2019 is illustrated. The calculation entails the use of 12 month average prices of the pricing benchmarks.

- **Step 1**

  Obtain the prices of Henry Hub, TTF Hub and NBP. Use the World Bank commodities prices 'Pink data' sheet and Ofgem to access these prices. This is shown in table 1 below.

Table 1: Natural Gas Prices

Year-Month	US HH	TTF	UK NBP
	\$/mmbtu	\$/mmbtu	p/therm
2018M01	3,88	6,66	50.44
2018M02	2,67	6,72	58.96
2018M03	2,69	6,70	64.3
2018M04	2,76	6,93	50.94
2018M05	2,78	7,49	55.58
2018M06	2,94	7,45	54.97
2018M07	2,80	7,60	57.93
2018M08	2,96	8,08	62.83
2018M09	3,00	9,52	73.72
2018M10	3,29	8,79	66.53
2018M11	4,14	8,27	64.37
2018M12	3,95	7,98	63.74
Average Price	**3,16**	**7,68**	**60.36**

- **Step 2**

  The international gas prices will be shown in US\$/mmbtu and UK p/therm and will need to be converted to Rands/GJ. The prices shown in table 1 will be converted to rands. An example of how this will be conducted is shown in table 2 below:

Table 2: Conversion from USD to ZAR

Year-Month	Exchange Rate	US HH	TTF
	U\$ to ZAR	R/mmbtu	R/mmbtu
2018M01	13,1997	51,22	87,94
2018M02	13,0852	34,96	87,92
2018M03	12,9933	34,98	87,02
2018M04	12,8782	35,56	89,22
2018M05	12,8166	35,69	95,96

2018M06	12,849	37,76	95,71
2018M07	12,8721	36,01	97,81
2018M08	12,9436	38,30	104,65
2018M09	13,0867	39,23	124,61
2018M10	13,1491	43,24	115,59
2018M11	13,1498	54,37	108,68
2018M12	13,2339	52,33	105,56
Average Price	**13,0214**	**41,08**	**100,03**

- **Step 3**

  Convert the prices in table 2 from R/mmbtu to R/GJ as shown in table 3 below:

Table 3: Conversion from mmbtu to GJ

Year-Month		US HH	TTF
	mmbtu to GJ	R/GJ	R/GJ
2018M01	1,055	48,55	83,36
2018M02	1,055	33,14	83,33
2018M03	1,055	33,15	82,48
2018M04	1,055	33,71	84,57
2018M05	1,055	33,82	90,96
2018M06	1,055	35,80	90,72
2018M07	1,055	34,13	92,71
2018M08	1,055	36,30	99,19
2018M09	1,055	37,18	118,11
2018M10	1,055	40,98	109,57
2018M11	1,055	51,54	103,02
2018M12	1,055	49,60	100,05
Average Price	**1,055**	**38,94**	**94,81**

- **Step 3.1**

  The same conversions will also be conducted for the UK price as shown in table 4 below:

Table 4: UK price conversion from GBP/therm to R/GJ

Date	UK NBP Prices	Conversion to GJ		Conversion to ZAR	UK NBP
	GB pence/therm		GB pence/GJ	GBP to ZAR	R/GJ
	a	b	c=a*b	d	e=(c*d/100)
2018/01/01	50.44	9.48	478.17	16.88	80.73
2018/02/01	58.96	9.48	558.94	16.27	90.92
2018/03/01	64.30	9.48	609.56	16.62	101.33
2018/04/01	50.94	9.48	482.91	17.20	83.05
2018/05/01	55.58	9.48	526.90	16.86	88.82
2018/06/01	54.97	9.48	521.12	18.10	94.35
2018/07/01	57.93	9.48	549.18	17.18	94.34
2018/08/01	62.83	9.48	595.63	19.05	113.47

2018/09/01	73.72	9.48	698.87	18.45	128.94
2018/10/01	66.53	9.48	630.70	18.87	118.98
2018/11/01	64.37	9.48	610.23	17.69	107.92
2018/12/01	63.74	9.48	604.26	18.36	110.96
Average					**101.15**

- **Step 4**

  The last step would be to calculate the maximum price. The formula for calculating the maximum price will be as shown in paragraph 3.1 above. The calculated maximum price to be used in January 2019 as per this example will be as shown below:

Table 5: January 2019 Maximum Price

	R/GJ	Weight	**R/GJ**
US Henry Hub	38,94	40%	**15,58**
TTF (Netherlands)	94,81	50%	**47,41**
NBP (UK)	101.15	10%	**10,12**
Maximum Price			**73,11**

The example illustrates that the maximum price for an applicant for January 2019 would be R73.11/GJ.

8. Implementation of the rationality test

NERSA will also ensure that the maximum price achieves the objectives of the Gas Act and will ensure the following:

- **Step 5**

  NERSA will establish the licensees costs of purchasing the gas molecule. For example such costs may be estimated to be R45/GJ. NERSA will use the actual costs of the applicant for this exercise.

- **Step 6**

  Establish the Japan LNG price. Use the World Bank commodities prices 'Pink data' sheet. The Japanese LNG price is published (excluding the average) as shown below. For instance, in January 2019, the Japanese Asian Price to be considered is U$ 10.67/ mmbtu. The price will need to be converted to rands using the monthly average exchange rate of 2018 that is shown below.

Table 6: Average LNG price

Year/month	USD/mmbtu
2018M01	9.34
2018M02	9.83
2018M03	10.11
2018M04	10.09
2018M05	10.25
2018M06	10.44
2018M07	10.44
2018M08	10.88
2018M09	11.30
2018M10	11.66
2018M11	11.70
2018M12	12.00
Average	**10.67**

Table 7: Average Exchange Rate

Period	USD to ZAR
Jan-18	13.1997
Feb-18	13.0852
Mar-18	12.9933
Apr-18	12.8782
May-18	12.8166
Jun-18	12.849
Jul-18	12.8721
Aug-18	12.9436
Sep-18	13.0867
Oct-18	13.1491
Nov-18	13.1498
Dec-18	13.2339
Average	**13.0214**

The above average prices will be used to establish the Japan LNG price as shown below:

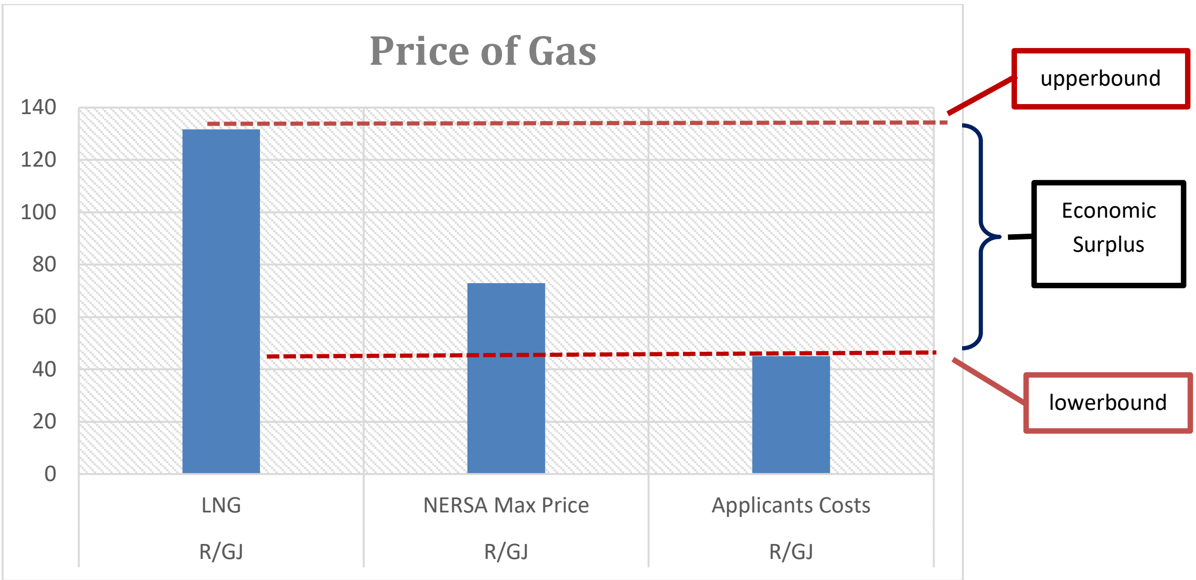
Table 8: Japan LNG Price

	LNG price $/mmbtu	Exchange rate USD/ZAR	R/mmbtu	Conversion mmbtu to GJ	R/GJ
LNG price	10.67	13.0214	138.94	1.055	131.69

The Japan LNG price converts to R131.69/GJ and it represents the upper bounds of the piped gas market. Step 5 and step 6 are required in establishing the economic surplus prevailing in the piped gas market.

Graph 1 below shows that the maximum price lies between the lower bound and upper bound of the gas market. The distance between the lower bound and the upperbound shown in the graph represents the total economic surplus. The maximum price should lie between the lower bounds and the upper bounds of the piped gas market. It is an objective way of allocating the total surplus between the suppliers of gas and the consumers.

Graph 1: Equitable allocation of economic surplus



9. Utilisation of maximum gas prices in defining prices per customer class

NERSA will in terms of this methodology approve a single maximum price per licensee. Section 22 of the Gas Act then provides details on how an applicant applies objective features to differentiate prices. Annexure A of the Piped-gas Regulations prescribes the different classes of customers for which maximum prices must be approved. A licensee must apply for maximum prices for each customer class and each customer category's price must be below the maximum price as approved by the Energy Regulator for that licensee. The table of customers as per Annexure A of the Piped-gas Regulations is provided below as table 8 :

Table 8: Customer classes

Annual consumption	
Class 1	Less than 400 GJ
Class 2	401 GJ p.a to 4 000 GJ p.a
Class 3	4001 GJ pa to 40 000 GJ p.a
Class 4	40 001 GJ pa to 400 000 GJ p.a
Class 5	400 001 GJ pa to 4000 000 GJ p.a
Class 6	>4 000 000 GJ pa

10. Data Sources

In order to provide certainty and predictability the following data sources will be used for the various elements in the formula for the approval of maximum price of piped-gas energy. Licensees are also allowed to propose other sources not listed below subject to approval by the Energy Regulator.

Variable Element	Source of data
a) Prices of Henry Hub, TTF and Japan Gas Prices	World Bank Commodity Prices Publication 'Pink Data' sheet
b) NBP	https://www.ofgem.gov.uk/data-portal/wholesale-market-indicators; Bloomberg
c) JKM	Platts; Australian Competition and Consumer Commission
d) Inputs for Weighted Average Cost of Capital (WACC) for Trading cost	Approved data sources for Tariff Guidelines published on NERSA website
e) Financial information to determine piped-gas trading costs of a licensee	As prescribed by the Regulatory Reporting Manuals vol 3
f) Exchange rates	South African Reserve Bank - Historical exchange rates (monthly mean) South African Revenue Service (SARS)

11. Implementation and transitional arrangements

This Methodology will come into effect after a transitional period of 3 months from date of approval by the Energy Regulator. Applicants that require a longer period to fully transition from the current methodology to the new methodology will seek approval from the Energy Regulator.

12. Review and modification of the Methodology

This Methodology will be reviewed periodically after every five years or as and when it may be necessary based on changes and developments in the gas industry.

13. Appendices

13.1. Appendix 1 – Determination of WACC

The weighted average cost of capital is the average of the cost of equity and debt, weighted by the proportions of equity and debt which an efficiently financed company can be expected to use to fund its activities. Hence, to determine the WACC, it is necessary to determine the cost of debt and equity and the proportions of debt and equity that would be employed in an efficiently financed company.

When determining the revenues and trading costs, the regulator must allow not only for the post-tax WACC return but must also allow for tax shield relating to debt finance. Since the tax treatment of debt (deductible as a cost) is different from the tax treatment of equity (not deductible as a cost), the allowed revenues to fund taxation will be a function of the proportions of debt and equity that would be employed by an efficiently financed business.

Trading licensees will be expected to submit their WACC calculations based on evidence regarding the cost of debt and the cost of equity. Internationally recognised approaches to the calculation of cost of debt and the return on equity should be used (for example with the Capital Asset Pricing Model (CAPM) for the cost of equity).

The following formula is used to determine the WACC using CAPM –

$$\boxed{WACC = \left[\left(\frac{E}{Dt + E}\right) * Ke\right] + \left[\left(\frac{Dt}{Dt + E}\right) * Kd\right]}$$

Where:

E= equity

Dt= debt

Ke= the cost of equity in terms of the Capital Asset pricing Model (CAPM)

Kd= the cost of debt

CAPM is the preferred approach as it is the most common methodology in the determination of cost of capital. However, if CAPM is considered to be inappropriate, companies have the opportunity to submit based on any other internationally recognized and used cost of capital approaches.

Applicants are expected to provide a rationale for the approach used, and this will be assessed by the Energy Regulator on a case-by-case basis.

When prices and trading costs are considered by NERSA, the trading cost will be approved at a level to ensure that appropriate levels of financial ratios will be met, based on prevailing financial market conditions and best practices in South Africa.

If the Capital Asset Pricing Model is adopted for the calculation of WACC, one of the key components that will need to be estimated is Beta.

Cost of equity

The cost of equity is the rate of return available on alternative equity investments of comparable risk. In the WACC formula, it is calculated as:

$$\boxed{Ke = r(f) + \beta(e) * MRP}$$

where:

r(f) is the risk-free rate. It represents the return an investor can achieve on the least risky asset in the market. Generally government bonds are used when estimating the cost of capital.

β (e) is the equity beta, which measures the covariance between the return on the firm's equity and the returns from the stock market as a whole. Beta is an important parameter calculated by the regulator, and more details on its calculation is provided below.

MRP is the market risk premium, which represents the additional expected return investors require to invest funds into equities rather than risk-free instruments. It can be calculated using historical averages and/or market based forward looking approaches. At present historical averages is the preferred method.

Beta

β = 'beta', is the measure systematic risk parameter for regulated entities providing gas trading services and facilities. The methodology to be used to determine the beta is set out below:

For licensees that are not publicly listed and where there are insufficient publicly listed competitors the equity beta must be determined by proxy. As a proxy the average of six (6) pipeline (international) companies listed on stock exchanges must be used (approved by the Energy Regulator). To make adjustments for differences in gearing between the proxy and the licensee the process involves and ‘unlevering’ and ‘relevering’ as follows:

- Obtaining the equity beta for the proxy company
- Unlevering the beta of the proxy company by the gearing level of the proxy company. This unlevered beta is known as the asset beta.
- Calculating the weighted average of the asset betas for the chosen proxy companies
- Relevering the average asset beta by the (optimal) gearing expected of an efficiently financed licensee to fund its licensed activities

The following steps and formulae must be used:

<u>Step 1 – Calculate asset beta (or unlevered beta) for proxy firm</u>

The following formula must be used to determine the asset beta –

$$\beta_{a1} = \frac{\beta 1}{1 + [1 - Tr] * \left[\frac{D}{E}\right]}$$

Where:

β_{a1} =	asset beta for proxy company 1
$\beta 1$ =	beta of proxy company 1 (will be given)
Tr =	tax rate of relevant country
D =	debt
E =	equity

Repeat step 1 for each of the 6 chosen proxy companies.

<u>Step 2 – Calculate weighted average asset beta of proxy companies</u>

Weight each of the 6 proxy firm asset betas by their proportion of the total debt plus equity of the 6 proxy firms and sum the 6 results using the following formula –

$$\beta_a E = \sum_{n=1}^{6}\left[\left(\frac{(D+E)n}{\sum_{n=1}^{6}(D+E)n}\right) * (\beta a)_n\right]_n$$

Where:

$\beta_a E$ = weighted average asset beta of the regulated entity

$(D+E)n$ = sum of the debt and equity for a specific proxy company

$(\beta a)_n$ = asset beta of the corresponding specific proxy company

$\sum_{n=1}^{6}(D+E)n$ = sum of debt and equity for all proxy companies

<u>Step 3 – Calculation of beta (β) for licensee</u>

The following formula must be used to determine the beta for the licensee –

$$\beta_L = [WA\ \beta][1+(1-t)(D/E)]$$

Where:

B_L = beta for the licensee

WA β = the weighted average β of the proxy firms asset betas from Step 2.

t = tax rate of the licensee

D = the debt of the licensee subject to a minimum gearing level of 30%

E = the equity of the licensee

Cost of debt

The actual cost of debt incurred by the licensee must be allowed subject to the Energy Regulator finding it reasonable through the application of reasonableness tests.

The actual cost of debt must be determined by estimating the actual weighted average interest charged on debt achieved by the licensee for the tariff period under review.

Where actual cost of debt is not known then the lenders estimate of cost of debt for the forthcoming pricing period must be used. Where the licensee has business activities that are not regulated by the Energy Regulator and the licensee raises corporate debt then the actual cost of debt charged to the regulated activities must fairly reflect the risks of those regulated activities as prescribed in the RRM and approved by the Energy Regulator in a Cost Allocation Manual;

The cost of debt is calculated as:

$$\boxed{\mathbf{Kd = r(f) + Dp}}$$

where:

r(f) is the risk free rate

Dp is the borrowing / debt margin or yield.

The debt margin represents the difference in the redemption yield on a corporate bond and the yield on a government bond (the risk-free rate). Lenders require a higher return for lending to a company rather than a government due to higher default risk.