An Coimisiún um Rialáil Fóntas
Commission for Regulation of Utilities

Gas Transmission Tariffs Article 30 Tariff Network Code Information 2020/21

Information Paper

Information Paper

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Executive Summary

In June 2020, the Commission for Regulation of Utilities (CRU) reviewed and published a decision on transmission tariffs for the gas year 2020/21. The gas year 2020/21 runs from 01 October 2020 to 30 September 2021. The Commission's decision was published on 05 June (see CRU/20/059) and will see gas transmission tariffs increase on 01 October 2020. The decision was published one month in advance of gas capacity auctions which were held in July 2019. Its publication was required under the Tariff Network Code[1] (TAR NC), specifically Article 29.

Article 30 of the TAR NC sets out further detailed information that must be published prior to the tariffs coming into force in October 2020. This paper sets out the required information and also provides additional information with the aim of making it a useful guide for transmission tariffs. The document includes:

- an introduction to the methodology used to calculate the tariffs;
- an introduction to how the CRU sets Gas Network Ireland's (GNI) allowed revenue;
- a description of the annual process that the CRU follows to update GNI's allowed revenues;
- information required under Article 30 of TAR NC, containing:
    - detail on elements of the CRU's Allowed Revenue methodology;
    - detail on the parameters within GNI's tariff model; and,
    - other additional information used either directly or indirectly to calculate GNI's allowed revenue and the transmission tariffs.
- the variables that cause changes in the tariffs from one year to the next; and,
- the transmission tariffs for the gas year 2020/21.

A simplified transmission tariff model is also being published alongside this paper. The model is available at the following link. Users can change the inputs into this model to try and estimate possible impacts of different scenarios on tariffs. As it is a simplified model, developed for ease of use and interpretation, it can only provide broad

[1] Establishing a network code on harmonised transmission tariff structures for gas (Commission Regulation (EU) 2017/460).

indications of tariff movements. It should not be relied upon for business decisions but rather should be used as a useful guide to further understand how tariffs may possibly react under different scenarios.

Public Impact Statement

The CRU approves the gas network tariffs to ensure that only necessary and efficient costs are included. It is important that the calculation of those costs is transparent, accessible and publicly available.

The cost of networks tariffs is recovered by suppliers who are charged network charges for use of the network, these charge are then applied to gas customers' bills It is estimated that network tariffs account for approximately 28% of a household's gas bill. In competing for business suppliers set their own tariffs choosing what amount they seek to recover from customers.

In June of this year the CRU published its decision on gas transmission tariffs for the gas year 2020/21, which will run from 01 October 2020 to 30 September 2020. The CRU's decision was based on a thorough review of a submission from Gas Networks Ireland and approved an increase in transmission tariffs. If suppliers were to pass this increase on to final customers, it would increase a residential gas customer's annual bill by c. 0.2% or approximately €2 in a year. However, the CRU would note that the pricing decisions of suppliers do not just reflect network charges but also the other charges they are faced with. For example, suppliers may be experiencing additional costs relating to the current pandemic, but they are also likely to be experiencing reduced wholesale gas costs.

This paper is an annual publication, which provides a more detailed breakdown of the CRU's decision on transmission tariffs in terms of specific allowances. This is in accordance with European requirements. It also provides a high level overview of how tariffs are calculated and what causes them to change from one year to the next. A simplified tariff model is also been made available on Gas Networks Ireland's website at the following link.

This document provides further details on transmission tariffs and aims to create a single resource for all gas transmission tariff related information such as; (1) details of the tariff model that is used to calculate tariffs, (2) the process that the CRU follows in updating tariffs, and (3) how the CRU sets the allowed revenue for Gas Networks Ireland (GNI).

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
AGI	Above Ground Installation
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CNG	Compressed Natural Gas
CRU	Commission for Regulation of Utilities
DM	Daily Metered
GNI	Gas Networks Ireland
GCS	Generation Capacity Statement
HICP	Harmonised Index of Consumer Prices
I/C	Industrial & Commercial
IP	Interconnection Point
LDM	Large Daily Metered
LRMC	Long Run Marginal Costs
NDM	Non-Daily Metered
Opex	Operating expenditure
RAB	Regulated Asset Base
RNG	Renewable Natural Gas
RPM	Reference Price Methodology
TSO	Transmission System Operator
VRF	Virtual Reverse Flow
WACC	Weighted Average Cost of Capital

1 Introduction

1.1 The Commission for Regulation of Utilities

The Commission for Regulation of Utilities (CRU) is Ireland's independent energy and water regulator. The CRU was established in 1999 and has a wide range of economic, customer protection and safety responsibilities. The CRU's mission is to regulate water, energy and energy safety in the public interest.

Further information on the CRU's role and relevant legislation can be found on the CRU's website at www.cru.ie .

Under the Gas (Interim) (Regulation) Act, 2002, the CRU is responsible for regulating charges in the natural gas market. Under Section 14 of the Act, the CRU may set the basis for charges for transporting gas through the transmission system.

In line with these powers the CRU published a decision on GNI's allowed revenues and transmission tariffs that will apply from 01 October 2020 to 30 September 2021[2]. The CRU is now publishing additional information related to the calculation of allowed revenues and transmission tariffs. This is in accordance with Article 30 of the Network Code on rules regarding harmonised transmission tariff structures for gas (TAR NC)[1].

1.2 Purpose of the Paper

The purpose of this paper is to create a single resource for all tariff related information such as:

1. how the CRU sets tariffs on an annual basis,
2. the tariff methodology used,
3. the variables that cause changes in the tariffs from one year to the next and
4. the transmission tariffs for the gas year 2020/21 (published in CRU/20/059). The publication of this information is to provide customers with tariff related

[2] Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2020/21 – Decision Paper CRU/20/059 .

information in the most transparent and easily accessible manner.

1.3 Related Documents

Over the years there has been a large volume of tariff documentation published. The below provides a convenient list of some of the key transmission tariff.

- Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2020/21 – Decision Paper (CRU/20/059)
- CRU Transmission Revenue Model 2020/21 (CRU/20/059a)
- CRU Corrib Linkline Model (CRU/20/059b)
- GNI's Simplified Transmission Tariff Matrix Model
- Decision on October 2017 to September 2022 Transmission Revenue for Gas Networks Ireland (CER/17/260)
- Harmonised Transmission Tariff Methodology for Gas Decision Paper (CRU/19/060)
- Establishing a Network Code on Harmonised Transmission Tariff Structures for Gas (Commission Regulation (EU) 2017/460)
- Gas Networks Ireland Distribution Tariffs and Allowed Revenue 2020/21 – Decision Paper (CRU/20/076)
- CRU Distribution Revenue Model 2020/21 (CRU/20/076a)

1.4 Structure of the Paper

This information paper is structured as follows:

- Section 1 provides background as to the Irish transmission system and how transmission tariffs are calculated;
- Section 2 outlines the way by which tariffs are updated and how the CRU updates allowed revenues on an annual basis;
- Section 3 provides specific information required by Article 30 of the TAR NC; and
- Section 4 sets out the transmission tariffs for 2020/21 as published in CRU/19/059.

2 Irish Transmission Network

2.1 Introduction

The gas transmission and distribution networks are a key element of the energy sector in Ireland, delivering fuel to power stations as well as serving industrial, commercial and household consumers. This section provides a summary of the key economic and technical characteristics of the Irish gas transmission system, an outline of the reference price methodology[3] (RPM) (Matrix methodology) and the parameters used within the Matrix methodology.

2.2 Irish Transmission Network

The natural gas transmission network is 2,477km in length, consisting of high-pressure steel transmission pipelines. There are both onshore and offshore pipelines. See Figure 1 for a map of the Irish gas transmission system. The offshore portion of the network consists of the two gas interconnectors (IC1 and IC2) that connect Ireland to Brighouse Bay, Scotland. There is a sub-sea offtake point from IC2 that supplies the Isle of Man depicted in Figure 1.

The onshore network covers the country in a ring-shaped fashion linking Dublin, Galway, and Limerick. It also consists of several spur lines to Cork, Waterford and lower pressure local area (regional) networks in large urban centres. In addition, the Mayo-Galway pipeline connects the ring-main to the Bellanaboy terminal, Co. Mayo, where gas from the Corrib gas field enters the Irish transmission system. At the end of 2015 the Corrib entry point (known as Bellanaboy) came into operation. The Bellanaboy entry point and the Moffat interconnection point (IP) in Scotland are the only entry points in operation since flows ceased in mid-2020 from the Inch entry point for gas from the Kinsale gas fields. In addition, to the Moffat IP there is also an IP with the Northern Irish gas transmission system at Gormanston. However, no commercial gas currently flows to NI from the Irish system and this pipe is currently used for

[3] Reference Price Methodology (RPM) is the methodology applied to the part of the transmission services revenue to be recovered from capacity-based transmission tariffs with the aim of deriving reference prices.

emergency support only. In the event that commercial flows to Northern Ireland (NI) did occur the Gormanston IP could also become an entry point for virtual reverse flow (VRF) from the NI system to the Irish system.

Figure 1 Gas Network Ireland's transmission system

2.3 Transmission Tariff Methodology for Gas

Last year, in line the European network code on harmonised transmission tariff structures for gas (TAR NC)[4], the CRU completed a review of the methodology for

[4] Establishing a network code on harmonised transmission tariff structures for gas (Commission Regulation (EU) 2017/460).

calculating transmission tariffs for gas. The aim of the TAR NC was to overcome issues relating to Member States using different approaches to tariff setting for gas transmission services, which could add to the complexity of using the various transmission systems. As part of the tariff methodology review process, the CRU held a number of industry stakeholder workshops and published a consultation paper which set out key proposals and invited comments from interested parties. In June 2019, the CRU set out its decision in CRU/19/060. A key component of that paper was the CRU's decision to continue to calculate transmission tariffs using a forward-looking Matrix RPM, also referred to as the Matrix model. This Matrix model was used to set the tariffs for the 2020/21 gas year. In accordance with Article 30 of the TAR NC a simplified version of this Transmission Tariff Model is available alongside this information paper at the following link. Some of the key inputs to this methodology are highlighted in Table 4.1.

2.4 Parameters used in the Matrix Methodology

In accordance with Art. 30 (1)(a)(i) of the TAR NC, this section includes information on parameters used in the Matrix RPM that relate to the technical characteristics of the transmission system.

The Matrix RPM is a forward-looking methodology based on long run marginal costs (LRMC). The model contains a representative network of pipelines, which is based on actual pipeline distances between entry points and exit points in Ireland. The model uses these distances and an estimate of the cost of building additional gas pipeline capacity (i.e. expansion constant) to approximate the cost of expansion between each entry and each exit point in a matrix. To determine the reference price at each of the points, a mathematical formula uses least squares to minimise the total difference between the cost of the paths and the sum of the entry and exit reference price. Following this step, the 'primary' tariffs are rescaled to recover any transmission services revenue shortfall. The same approach is applied at exit.

As noted above, the cost of expansion is calculated using expansion constants. An expansion constant provides a numerical value for the cost of expanding capacity so that one unit of gas travels over a specified distance. This is measured in €/gigawatt hour/day/kilometre (€/GWh/d/km). To determine the values of an expansion constant,

actual pipeline and compressor capital and operating costs are used to forecast forward-looking costs. As the GNI system is comprised of both dry (onshore) and wet (subsea) pipelines, the CRU has calculated separate expansion constants to reflect the different costs associated with each. Both dry and wet expansion constants are comprised of pipeline costs and compression costs.

The expansion constant can be used to calculate the cost of building a pipeline (including compression) but it does not give any indication of the annual revenues that would be required to finance such an asset. In order to calculate the annual revenues an annuitisation factor is used. The annuitisation factor uses the capital costs of the assets, the cost of capital, the annual depreciation and the annual operating costs to calculate the average annual payment that would be made on this asset over the lifetime of the asset.

The wet expansion constant is €8,783 GWh/d/km, and the dry is 7,810 GWh/d/km. See CRU/18/247 sections 4.7 & 4.8 for further information on expansion constants and annuitisation factors. Table 2.1 below outlines further details required under Article 30 of the TAR NC relating to the parameters used with the Matrix model.

Table 2.1 Parameters used in the reference price methodology

TAR NC Article	Description	Detail
Art. 30(a)(i)	Technical capacity at entry and exit points	The technical capacity at the entry points to the transmission network is available on GNI's transparency dashboard, available at the following link. However, it should be noted that the technical capacity at entry and exit points of the transmission network is not a relevant variable for the purpose of the methodology of calculation of the transmission tariffs.
Art. 30(a)(ii)	Forecasted contracted capacity at entry and exit points	The forecasted contracted capacity at the entry points and at exit is available in Table 3.2. The assumptions underlying the calculation of forecasted contracted capacity are detailed in Table 3.1.
Art. 30(a)(iii)	Quantity and direction of the gas flow for entry and exit points	Demand is assumed to be met first by domestic production (i.e. Bellanaboy), with Moffat providing the marginal source of gas. The direction of gas flow from entry to exit is not a variable in the Matrix RPM that effects the calculation of the transmission tariffs. However, a representation of how gas flows around the network is available on GNI's transparency dashboard, available at the following link.

TAR NC Article	Description	Detail
Art. 30(a)(iv)	Structural representation of the transmission network	The structural representation of the GNI's transmission system is provided in Figure 1.
Art. 30(a)(v)	Additional technical information related to the transmission system, such as length and diameter of pipelines	The information involved in the calculation of the expansion constants and annuitisation factor has been provided in CRU/18/247. The files which detail the calculation of these parameters are available for download at the following link.

3 Tariff Setting Process

3.1 Introduction

This section outlines how the CRU sets GNI's allowed transmission revenue every five years through a process known as a Price Control. It also details the process followed by the CRU in setting the transmission tariffs on an annual basis. By charging these tariffs, GNI recovers its allowed revenue, as approved by the CRU.

3.2 Price Control

The CRU's role is to protect gas customers by ensuring that GNI spends customers' money appropriately and efficiently to deliver necessary services. The CRU does this through what is called a Price Control, which is carried out every five years. The current five year period started on 01 October 2017 (PC4). A Price Control sets out the allowed revenue for the 5 year period to ensure that GNI can safely operate, maintain and invest in the network effectively.

The transmission business's allowed revenue is made up of three parts:

i. Revenue to cover the transmission business's operational costs;

ii. A return on capital on the transmission business's assets; and,

iii. Revenue to cover depreciation of the transmission business's assets.

In August 2017, the CRU published its decision paper (CER/17/260) on the allowed revenue that GNI's transmission business may recover over the Price Control period from 01 October 2017 to 30 September 2022. That decision allowed €924m to be recovered for transmission over the 5-year period.

GNI as the transmission network operator, then recovers this allowed revenue on an annual basis through network tariffs which are set by the CRU. Network tariffs are charged to gas suppliers who may choose to pass them on to their customers.

3.3 Annual tariff setting process

As part of the annual tariff setting process, the CRU analyses any additional revenue requests from GNI (pass-through costs and extra-over items), over/under recoveries in the previous years and updated demand projections. These items are now discussed.

3.3.1 Pass-through costs and extra-over items

Each year GNI send a tariff submission to the CRU. This submission includes requests for additional revenues which are considered either pass-through costs or extra-over items. Pass-throughs are cost items that GNI has no control over or limited control over. Extra-over items are generally new capex or opex work items that could not have been reasonably foreseen at the time the Price Control was set.

For the gas year 2020/21 the CRU decided to allow GNI an additional €9.83m for pass-through costs. This includes an additional allowance for a 'typical' pass-through cost item, in this case €181k for the CRU levy. In addition, the CRU has provided an allowance for an extra-over item, i.e. €9.6m for shrinkage[5]. Currently, the transmission business' shrinkage costs are not included in the allowed revenue and are therefore not recovered through tariffs. Instead GNI bills these costs to gas shippers directly on a monthly basis, based on their throughput. However, as part of the CRU's tariff network code decision (CRU/19/060), it was decided that from 2020/21 onwards, shrinkage should be included in the allowed revenue. As this is not a new cost, it does not increase the costs faced by shippers or end customers.[6]

The CRU decided to treat the expenditure associated with shrinkage as a pass-through cost so that any costs not spent can be recovered as part of the k-factor.[7] For this reason, it is included in the €9.83m pass-through cost allowance. GNI did not seek any other transmission extra-over items for 2020/21.

[5] Shrinkage gas includes own use gas (OUG), which is gas used to operate the network and unaccounted for gas (UAG) (e.g. gas losses).
[6] Apart from some minor distributional impacts.
[7] The CRU will review whether shrinkage should continue to be treated as a pass-through cost as part of its Price Control 5 decision.

3.3.2 Correction Factor (or k-factor)

As transmission tariffs are calculated in advance, the CRU must use forecast data i.e. forecast inflation, revenues and pass-through costs. However, once actuals are available, we carry out an adjustment to take those into account. This is called a Correction Factor or k-factor adjustment. The k-factor is for 2 years previous as that is when the actual data is available i.e. when setting the tariffs for 2020/21 the CRU closes out the year 2018/19. Having reviewed the actual data for 2018/19, it has been determined that GNI has over recovered for that gas year. The over recovery is €9.45 million. This money will be returned to the customer, with interest, through the k-factor mechanism previously mentioned. The formula for the k-factor is set out in CER/03/170. There are two key rules to the k-factor. These rules are in place to ensure that tariffs are stable and to ensure that volatility is avoided. The rules are as follows:

Rule 1. Any over-recovery up to 105% of allowed revenues is returned in the following gas year (e.g. any 2018/19 k-factor >105% is returned in gas year 2021/22 not gas year 2020/21). This is to ensure that the tariffs are stable and that volatility is avoided.

Rule 2. Any over- or under-recovery of revenue attracts an interest rate of Euribor (interbank lending rate) +2% and any over-recovery in excess of 103% of revenue attracts an interest rate of Euribor +4% (e.g. any 2018/19 k-factor >100% & <103% is returned at Euribor +2% and any 2018/19 k-factor >103% & <105% is returned at Euribor +4%)[8]. This is to incentivise GNI to make accurate forecasts of demand and new customer connections.

As per rule 1 above, any over-recovery in excess of 105% of allowed revenues is to be returned in the following gas year. The 2018/19 over recovery of €9.45 million exceeds that rule. This results in €9.05m to be returned to the customer in 2020/21 (€9.45m when interest is applied) and €0.57m in 2021/22. It should also be noted that there was also an over-recovery in excess of the 105% rule in 2017/18, and this

[8] As per rule 1 any 2018/19 k-factor >105% is credited the following year, with Euribor +4% applied for both years.

money (€10.88m) is still to be returned to customers.[9] In total €11.45m[10] (not including interest) is to be credited to gas customer's next year.

The CRU carefully considered crediting the €11.45m to customers in this tariff year. However, on balance, this was not considered in the customer's best interest. The Covid-19 pandemic has increased the uncertainty surrounding gas demand forecasts and Covid-19 may impact network costs in the future. The €11.45m due to be credited next year will assist in offsetting some upward cost pressures that may arise when setting the tariffs for 2021/22. This approach will provide a buffer and may avoid customers facing more significant tariff increases in the coming years.

In addition to the above k-factor, c.€4m is being accrued to customers in each year of PC4 as part of the CRU's decision to spread out a 2016/17 over-recovery evenly across each year of PC4.

3.3.3 Demand Projections

In addition to information relating to expenditure, demand projections are also estimated through the Price Control process for each of the five years of the Price Control period. As part of the annual tariff setting process GNI submits updated demand figures which take into consideration the latest forecasts. These are reviewed and are used in setting the transmission tariffs.

In order to establish demand forecasts for 2020/21, GNI analysed the actual impact of Covid-19 on demand and then applied these learnings to the elements it typically uses to forecast gas demand for the coming gas year. When Covid-19 restrictions were put in place, there was a significant fall in gas demand, particularly in the industrial & commercial sector. However, since then demand has begun to recover and, overall, is broadly in line with expectations with seasonal demand.

[9] This was noted in Section 3.3.3 of CRU/19/111.
[10] €10.88m + €0.57m

3.3.3.1 Assumptions

The forecast demands for 2020/21 are based on the assumptions outlined in Table 3.1. These assumptions influence the demands forecasted at the Entry Points to the transmission system and at the Exit from the transmission system.

Table 3.1: Demand assumptions

Assumption	Description
Weighted Annualised Capacity Bookings	It is anticipated that shippers will continue to optimise their capacity bookings via a mixture of annual and short-term capacity products. This applies to the Large Daily Metered (LDM) and Daily Metered (DM) sectors[11]. Short-term capacity forecasts are weighted depending on the month when the booking is expected to arise. For example, if you buy a short-term capacity product in August it is cheaper than buying a short-term capacity product in February. This is due to a lower multiplier being applied. These multipliers are set out in Section 5.1. The value of these capacity products is converted into an annual value. In this way the forecast bookings are "annualised".[12]
Power generation	GNI's demand assumptions are based on Eirgrid's 2019-2028 Generation Capacity Statement (GCS) published in September 2019. Power demand is based on Eirgrid's Median Electricity Demand scenario. Adjustment applied to 2020/21 electricity forecast based on actual electricity demand (2019 demand was 3.5% below forecast) and impact of Covid-19 on power demand. The Power sector is expected to increase capacity bookings relative to the 2019/20 tariff demands due to overall growth in the electricity sector.
Daily Metered (DM) Industrial & Commercial (I/C)	The LDM & DM sector is expected to slightly reduce its level of capacity bookings relative to the 2019/20 tariff demands. The reduction in I/C is expected as some businesses will take longer to recover than others from impacts of Covid-19.
Non-Daily Metered (NDM)	The NDM sector capacity booking is derived by the Annual Quantity (AQ) and Supply Point Capacity (SPC) setting process in GNI, and there is a requirement on this sector to book a peak day (1 in 50) requirement at the Exit. The 1 in 50 has decreased in 2020/21 relative to the 2019/20 tariff demands.
Entry Points	Updated production profiles provided by the producers at Corrib have been utilised. Corrib Production has now come off peak and as a result capacity booking have decreased at Bellanaboy, resulting in increased capacity bookings at Moffat, which provides the marginal source of gas.

[11] The customer category classifications for LDM, DM and NDM are set out in the GNI Code of Operations under Part F, Section 2 Classification.
[12] An example of how capacity forecasts were annualised is shown in the 2014/15 Transmission Tariffs decision paper (CER/14/140).

3.3.3.2 Demand forecasts

Table 3.2 and Table 3.3 below presents GNI's transmission network demand forecasts for gas year 2020/21. For context these forecasts are presented alongside GNI's original forecasts for 2019/20 and its updated forecasts for 2019/20 (i.e. Covid-19 recast), which aim to take into account the effects of Covid-19 on gas demand.

Table 3.2: Transmission capacity demand forecast summary - MWh

	19/20 demand forecast	**19/20 Recast Covid-19 forecast**		**20/21 demand forecast**	**Variation vs 19/20 initial**	**Variation vs 19/20 update**
Bellanaboy Entry	*68,785*	*65,113*		*58,646*	*-15%*	*-10%*
Moffat Entry	*145,234*	*144,625*		*161,390*	*11%*	*12%*
WA[13] Total Entry Capacity	219,191	216,151		220,061	0%	2%
WA Total Exit Capacity	289,729	280,022		291,425	1%	4%

Note: The Entry Capacity is lower than the Exit Commodity as NDM customers are required to book for 1 in 50 at Exit.

Table 3.3: Transmission commodity demand forecast summary - MWh

	19/20 demand forecast	**19/20 Recast Covid-19 forecast**		**20/21 demand forecast**	**Variation vs 19/20 initial**	**Variation vs 19/20 update**
Entry Commodity	56,391	57,705		57,202	1%	-1%
Exit Commodity	54,908	56,295		55,869	2%	-1%

Note: The Exit Commodity total is lower than the Entry Commodity total primarily due to the Isle of Man offtake, which is not included in the Exit total.

[13] WA stands for weighted annualised. Shorter-term bookings, which can occur at different times of year (different costs) are adjusted for representation as an equivalent annual amount so that the overall demand can be compared more easily across years.

4 TAR NC Article 30 information

Article 30 of the TAR NC requires certain tariff information to be published ahead of the upcoming tariff period (i.e. gas year 01 October 2020 – 30 September 2021). This includes detail on elements of the CRU's allowed revenue methodology, GNI's Matrix Model, and other additional information all of which is used either directly or indirectly to calculate GNI's allowed revenue and the transmission tariffs for the 2020/21 gas year. Table 4.1 sets out this information. For further details, please refer to Article 30 of the TAR NC.

Table 4.1: Information on TSO Revenue - Revenue level

TAR NC Article	Description	Period	Detail	
Art. 30 (1)(a)	Information on parameters used in the reference price methodology that are related to the technical characteristics of the transmission systems	2020/21	See Section 2.4. A simplified version of the transmission tariff model is available on GNI's website at the following link. A full version of the tariff model is available from GNI at the following link.	
Art. 30 (1)(b)(i)	Allowed revenue	2020/21	€197.01m in transmission services revenue and €0.12 in non-transmission services revenue (20/21 monies).[14]	
Art. 30 (1)(b)(ii)	Changes in allowed revenue	2019/20 – 2020/21	Increase in allowed revenue by 12% from gas year 2019/20 to 2020/21. This increase is partly a result of the additional shrinkage allowance provided for in section 3.3.1. In addition, when setting the PC4 allowed revenue the CRU intentionally profiled the revenue to increase over the PC4 period in line with forecasted supply increasing at the more expensive Moffat entry point, resulting in greater levels of revenue recovery by GNI. This was done to enhance tariff stability.	
Art. 30 (1)(b)(iii)(1)	Asset types and their aggregated value	At start of current regulatory period – 01.10.2017	*Asset type*	*Net book value (15/16 monies)*
			Pipelines/AGIs (incl. GTTW)	€1246.4
			Land	€1.9m
			Equipment	€19.2m
			Compressors	€62.9m
			Buildings	€17.6m
			Total	€1348
Art. 30 (1)(b)(iii)(2)	Cost of capital and calculation methodology	2017/18-2021/22	4.63% WACC – cost of debt is calculated using the estimated yield on government bonds plus a debt premium, while the cost of equity is calculated using the CAPM model.	

[14] See section 3.3 of CRU/19/060 for further information on transmission and non-transmission revenue.

TAR NC Article	Description	Period	Detail		
Art. 30 (1)(b)(iii)(3)(a)	Initial asset valuation methodology	n/a	Acquisition cost		
Art. 30 (1)(b)(iii)(3)(b)	Asset revaluation methodology	n/a	Acquisition cost, indexed with inflation (HICP), as a proxy for current replacement cost.		
Art. 30 (1)(b)(iii)(3)(c)	Evolution of the value of the assets	n/a	Assets are added to the Regulated Asset Base (RAB) at their acquisition cost (historic cost). The assets are indexed with inflation (HICP) in order to calculate the value of an asset at the required point in time. The assets are then depreciated, using straight line depreciation, the rate of depreciation is set by the asset life. Assets are removed from the RAB when they are fully depreciated or disposed of.		
Art. 30 (1)(b)(iii)(3)(d)	Depreciation periods and amount per asset type	At start of current regulatory period – 01.10.2017	*Asset Type*	*Depreciation Period (Asset life)*	*Annual Depreciation Amount (15/16 monies)*
			Pipelines/AGIs/GTTW	50 years	€40.6m
			Land	40 years	€0.1m
			Equipment	5 years	€5.7m
			Compressors	25 years	€5.1m
			Buildings	40 years	€0.8m
Art. 30 (1)(b)(iii)(4)	Operational expenditures	2020/21	€73.9m		
Art. 30 (1)(b)(iii)(5)	Incentive mechanisms and efficiency targets	2017/18-2021/22	Capex and opex incentives[15], with an ongoing controllable opex efficiency challenge of 1%.		
Art. 30 (1)(b)(iii)(6)	Inflation indices	2017/18-2021/22	Harmonised Index of Consumer Prices[16]		
Art. 30 (1)(b)(iv)	Transmission services revenue	2020/21	€197.01m (20/21 monies)		
Art. 30 (1)(b)(v)(1)	Capacity-commodity split	2019/20	90:10		
Art. 30 (1)(b)(v)(2)	Entry-exit split	2019/20	33:67		

[15] See Section 7 of CER/17/260 for further detail regarding the incentives applied to the TSO.
[16] See 'Inflation' and 'Indexation' tab of CRU/19/061a Transmission revenue model 2019/20 for further detail.

TAR NC Article	Description	Period	Detail				
Art. 30 (1)(b)(v)(3)	Intra-system/cross-system split	2020/21	100% intra-system as there are currently no cross-system flows.				
Art. 30 (1)(b)(vi)(1)	Actual revenue recovered in kt-2 (i.e. 17/18)	2018/19	Actual revenue recovered was €189.03m in nominal monies.				
Art. 30 (1)(b)(vi)(2)	(i) Correction factor for the year Kt-2, (ii) its effect on revenues in year Kt (19/20) and (iii) incentives.	2018/19	See section 3.3.2 for explanation. (i) €9.6m, (ii) Reduced allowed revenue by €9.5m[17], (iii) Refer to Section 3.3.2.				
Art. 30 (1)(b)(vii)	Intended use of auction premium	2020/21	N/A - no auction premium applied				
Art. 30 (1)(c)(i)	Commodity-based tariffs	2020/21	See Table 5.1				
Art. 30 (1)(c)(ii)	Non-transmission tariffs	2020/21	The Corrib Linkline Element of the Bellanaboy tariff is considered a non-transmission tariff[18] under TAR NC. See Table 5.1				
Art. 30 (1)(c)(iii)	Reference prices for other points than interconnection points	2020/21	See Table 5.1				
Art. 30 (2)(a)(i)	Information about tariff changes and trends	2019/20 - 2020/21	See Appendix A for the difference in tariffs and Section 3 for an explanation of this difference.				
Art. 30 (2)(a)(ii)	Information about tariff changes and trends	2017/18 - 2021/22	A simplified model is available on GNI's website at the following link. This allows the calculation of the possible evolution of tariffs.				
Art. 30 (2)(b)	A simplified tariff model	2020/21	A simplified model is available on GNI's website link.				
Art. 30 (3)	Information on the amount of forecasted contracted capacity and the forecasted quantity of the gas flow on non-relevant points	2020/21	Market Segment	Unit	Forecasted Contracted Capacity[19]	Unit	Forecasted Gas Flow
			Power gen	MWh/d	147,179	GWh/y	31,736
			DM	MWh/d	44,544	GWh/y	11,989
			NDM	MWh/d	93,563	GWh/y	12,112
			CNG	MWh/d	244	GWh/y	33

[17] As the correction factor is in excess of the 105% rule €0.57m (not including interest) will be returned in 2021/22.
[18] Non-transmission services are "the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by transmission system operator".
[19] Weighted Annualised Capacity Bookings, see Table 3.1.

5 Transmission Tariffs 2020/21

The previous sections outline the elements affecting the transmission tariffs such as the adjustments which occur to the allowed revenues. These adjustments are then taken together with the allowed revenue from the Price Control to calculate the allowed revenue for the forthcoming tariff year. This allowed revenue is then inputted into GNI's Transmission Matrix Model along with the updated demand forecasts and correction factor to calculate the tariffs for the upcoming gas year. The transmission tariffs which will apply from 01 October 2020 to 30 September 2021 based on a revenue of €197.01m (2020/21 monies) are set out below.

Table 5.1: Transmission tariffs for 2020/21

	Bellanaboy entry	**RNG entry[20]**	**Moffat (IP) entry**	**Domestic exit**	**Gormanston (IP) exit**
Firm[21] capacity - €/peak day MWh	629.99[22]	106.24	314.81	407.63	385.37
Commodity - €/MWh	0.114			0.236	

With these updated tariffs, the transportation cost of GB gas to Ireland (Moffat entry tariff + domestic exit tariff) will increase in nominal terms by c.8%. The main reason for the 2020/21 increase in the cost of transportation of GB gas is that shrinkage costs have moved into, and therefore, increased the allowed revenue. This is being done in accordance with the CRU's 2019 decision on the harmonised transmission tariff

[20] As part of the CRU's decision on the Harmonised Tariff Methodology for Gas (CRU/19/060), a single transmission entry tariff has been set for RNG, based on one 'notional entry point' that is derived from the average of three geographically dispersed locations in counties Cork, Galway and Meath. There are currently no RNG entry points operational on the transmission network.

[21] "Firm" means gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator.

[22] This is composed of two elements; one to remunerate the transmission services revenue of GNI (€132.36) plus a Corrib Linkline Element (€497.64), which will remunerate the revenues relating to the Corrib Linkline (Corrib Partners).

methodology and in compliance with the EU tariff network code but should not lead to an increase in customer's bills.[23]

For comparison, Table 5.2 below provides the 2020/21 transportation cost of GB gas[24] in the context of recent years. The transportation cost of GB gas is important because, generally, Irish wholesale gas prices are generally set by the GB price of gas plus the cost of transporting gas from GB to Ireland via the interconnectors, as GB gas is the marginal source of gas supply to Ireland.[25] The table shows that this cost has fallen in recent years. This is because GNI has earned more transmission revenue than expected, putting downward pressure on tariffs. This has been caused by greater gas demand than was forecast and also more supply being met from the Moffat entry point than initially forecast.[26] Despite the c.8% increase, due to reductions in the previous three years, the cost of transportation of GB gas remains below 2016/17 and 2017/18 levels.

Table 5.2: Recent cost of transportation for GB gas (nominal)

	2016/17	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Capacity – €/peak MWh	788.605	761.263	715.864	669.00	722.44

As highlighted in the CRU's June Decision Paper (CRU/20/059), the CRU carefully considered its decision to allow an increase network tariffs in the context of the Covid-19 pandemic. Sustained large reductions in demand could cause significant upward pressure on tariffs. However, gas demand has recovered broadly to normal levels, since the pandemic began and the most up to date forecasts are indicating that demand, for the gas year 20/21, will be similar to previous years. There remain

[23] Shrinkage gas includes own use gas (OUG) and unaccounted for gas (UAG). To date shrinkage costs were not included in the allowed revenue and are therefore not recovered through tariffs. Instead GNI billed these costs to gas shippers directly on a monthly basis, based on their throughput. However, as part of the CRU's tariff network code decision (CRU/19/060), it was decided that from 2020/21 onwards, shrinkage should be included in the allowed revenue as it is a transmission service. As this is a movement of costs, not an increase in overall costs, it should not lead to an increase in costs for end customers.
[24] Moffat entry capacity tariff + domestic exit capacity tariff.
[25] Since 2017, an electronic trading platform (https://www.marexspectron.com/) has been in place in Ireland. As liquidity grows it will provide a more accurate representation of gas price in Ireland.
[26] The Moffat entry point is more expensive resulting in more revenue recovery by GNI.

uncertainties with Covid-19 and its impact on network costs and the CRU is continuing to monitor the situation carefully. The CRU did consider options to address any potential unsustainable increases in tariffs due to Covid-19. However, on balance, these are not considered appropriate. For example, they could build up costs for future years, which increases the risk of customers facing more significant tariff increases in the coming years.

5.1 Details of Multipliers

Multipliers and seasonal factors are applied to the reference prices to set the tariffs for non-yearly capacity products. Short-term multipliers are applied in order to, amongst other things, incentivise efficient booking and hence use of the network. Table 5.3 below outlines the multiplier and seasonal factor profile for gas year 2020/21. The CRU decided to not to change the profile for gas year 2020/21 as set out in its annual tariff network code Article 28 paper (CRU/20/057).

Table 5.3: Multiplier and seasonal factor profiles[27]

Month	Quarterly %	Monthly %	Daily %
October	38.43%	12.81%	0.64%
November		12.81%	0.64%
December		17.08%	1.14%
January	80.69%	29.89%	1.99%
February		34.16%	2.28%
March		25.62%	1.71%
April	13.27%	12.81%	0.64%
May		0.97%	0.05%
June		0.97%	0.05%
July	2.61%	0.97%	0.05%
August		0.97%	0.05%
September		0.97%	0.05%
Total	*135.0%*	*150.0%*	*279.44%*

[27] To understand how this works, consider the following example: The reference price for Moffat entry is €301/MWh. If you wanted to book monthly capacity for December, you could calculate the cost by referring to the table and applying the relevant combined multiplier & seasonal factor; in this case 17.08%. That would result in the following – €301/MWh * 17.08% = €51.4/MWh.

5.2 Virtual Reverse Tariff 2020/21

Virtual Reverse Flow (VRF) is a 'reverse flow' service offered on a virtual interruptible basis, at the Interconnection Points, to enable Shippers to virtually flow gas from Ireland via Moffat and into Ireland via Gormanston.[28] In accordance with the CRU's TAR NC decision paper, for gas year 2019/20 a new tariff was introduced for VRF, which replaced the previous registration fee approach. The calculation of the VRF tariffs at Moffat and Gormanston are now based on the TAR NC principles and requirements for standard interruptible capacity products. Art. 16 of TAR NC specifies the calculation of reserve prices for standard interruptible capacity products by applying an adjustment to the reserve prices for the corresponding standard firm capacity products.

Full details on how the CRU sets the VRF tariffs for Moffat and Gormanston and the reasoning for its approach, can be found in section 3.11 of the CRU's TAR NC decision paper (CRU/19/060), in summary:

- The VRF tariffs are based on the Moffat exit point and Gormanston entry point reference prices, as calculated by the Matrix RPM.
- A Pro Factor of 8% is applied to the Moffat and Gormanston VRF products, reflecting the probability of interruption.
- A risk premium of 10% is applied to both the Moffat and Gormanston VRF products.
- A market interaction factor of 30% applies to the Moffat VRF product only to bring the price below that of the equivalent forward flow tariff for reasons of cross-border trade.

These inputs result in an A-factor (i.e. overall adjustment) of 6 for Moffat VRF and an A-factor of 2.25 for the Gormanston VRF. The CRU decided to not to change the

[28] For example, if there is a total nomination of 100 units of gas for delivery from GB to ROI and a gas shipper in Ireland wishes to virtually transport 10 units of gas from ROI to GB, these 10 units are netted off the 100 units, resulting in the delivery of 90 units into the ROI gas network.

adjustment for gas year 2020/21 as set out in its annual tariff network code Article 28 paper (CRU/20/057).

Table 5.4: Virtual reverse flow (VRF) tariffs for 2020/21

	Gormanston (IP) VRF entry	**Moffat (IP) VRF exit**
Capacity – €/peak day MWh	76.15	270.86
Commodity - €/MWh	0.114	0.236

6 Conclusion

This information paper aims to provides a single resource for all tariff related information, ranging from; how it sets tariffs on an annual basis, the variables that cause changes in the tariffs from one year to the next, and the 2020/21 transmission tariffs. This is the second year that the CRU has published this information in one document. By making all tariff related information available to customers, in a single location, the CRU aims to make it easier for customers to understand how tariffs are set and what causes them to change from one year to the next. An important tool, also available to the public, is the simplified tariff model available on Gas Networks Ireland's website at the following link. This simplified model enables customers to further identify how transmission network tariffs are affected by demand and revenue variations, and to estimate possible evolution of tariffs.

Appendix A Transmission Tariffs 2020/21

GNI Transmission Tariffs for 2020/21	2020/21 Tariffs		Published Tariffs					
	€	(2020/21 Monies)	2015/16 Tariffs €	2016/17 Tariffs €	2017/18 Tariffs €	2018/19 Tariffs €	2019/20 Tariffs €	% Change Nominal from 2019/20
Exit								
capacity	**407.634**	per peak day MWh	430.882	428.352	402.080	389.884	367.658	11%
commodity	**0.236**	per MWh	0.267	0.256	0.238	0.235	0.216	10%
Gormanston Exit								
capacity	**385.366**	per peak day MWh	415.210	412.680	386.408	374.212	345.341	12%
commodity	**0.236**	per MWh	0.267	0.256	0.238	0.235	0.216	10%
Moffat Entry								
capacity	**314.810**	per peak day MWh	367.786	360.253	359.183	325.979	301.345	4%
commodity	**0.114**	per MWh	0.118	0.123	0.114	0.113	0.103	10%
Bellanaboy Entry								
capacity	**629.993**	per peak day MWh	617.996	610.463	658.431	630.428	619.442	2%
commodity	**0.114**	per MWh	0.118	0.123	0.114	0.113	0.103	10%
RNG Entry								
capacity	**106.239**	per peak day MWh					92.775	15%
commodity	**0.114**	per MWh					0.103	10%
Gormanston VRF Entry								
capacity	**76.151**	per peak day MWh					65.110	17%
commodity	**0.114**	per MWh					0.103	10%
Moffat VRF Exit								
capacity	**270.857**	per peak day MWh					250.044	8%
commodity	**0.236**	per MWh					0.216	10%
Illustrative Transmission Transportation Costs								
	€		€	€	€	€	€	
Transmission Transportation Cost of UK Gas								
capacity	**722.443**	per peak day MWh	798.668	788.605	761.263	715.864	669.003	8.0%
commodity	**0.350**	per MWh	0.385	0.379	0.352	0.348	0.319	9.7%
Transmission Transportation Cost of Bellanaboy Gas								
capacity	**1,037.627**	per peak day MWh	1048.878	1038.815	1060.511	1020.312	987.099	5.1%
commodity	**0.350**	per MWh	0.385	0.379	0.352	0.348	0.319	9.7%
Transmission Transportation Cost of RNG								
capacity	**513.873**	per peak day MWh					460.432	11.6%
commodity	**0.350**	per MWh					0.319	9.7%