An Coimisiún um Rialáil Fóntas

Commission for Regulation of Utilities

Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2021/22

Decision Paper

Decision Paper

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CRU Mission Statement

The CRU's mission is to protect the public interest in Water, Energy and Energy Safety.

The CRU is guided by four strategic priorities that sit alongside the core activities we undertake to deliver in the public interest. These are:

- Deliver sustainable low-carbon solutions with well-regulated markets and networks
- Ensure compliance and accountability through best regulatory practice
- Develop effective communications to support customers and the regulatory process
- Foster and maintain a high-performance culture and organisation to achieve our vision

Executive Summary

This paper sets out the transmission network tariffs to apply from 01 October 2021 to 30 September 2022 (gas year 2021/22). Article 29 of the Tariff Network Code[1], requires that transmission reserve prices and a set of accompanying information is published 30 days ahead of the annual yearly capacity auctions. The annual yearly capacity auctions will be held on 05 July 2021 for the forthcoming gas year which commences on 01 October 2021. As such this information needs to be made available by 05 June. Although it is not required under Article 29, the CRU is also publishing the distribution tariffs at this time, in a separate paper (CRU/21/059).

Each year, the network tariffs are reviewed to ensure that Gas Networks Ireland (GNI) only recovers the necessary costs for efficient operation of the network. The review uses the most up to date revenue and demand data, as submitted by GNI.

In its review of transmission tariffs, the CRU has carefully assessed the information presented by GNI and has aimed to ensure that where additional allowances have been provided, they are efficient and in the best interest of the customer. The review has resulted in the following tariffs outlined in Table 1.

[1] Commission Regulation (EU) 2017/460 – 16 March 2017

Table 1: Transmission tariffs 2021/22

	Bellanaboy entry	RNG entry	Moffat (IP) entry	Domestic exit	Gormanston (IP) exit
Firm[2] capacity - €/peak day MWh	633.76[3]	104.32	312.89	454.70	432.40
Commodity - €/MWh	0.114			0.238	

For comparison, Table 2 below provides the 2021/22 transportation cost of Great British (GB) gas in the context of recent years. The transportation cost of GB gas (Moffat Entry capacity tariff + Domestic Exit capacity tariff) is important because GB gas is the marginal supply for Ireland. Generally, Irish wholesale gas prices are set by the GB price of gas plus the cost of transporting gas from GB to Ireland via the interconnectors. The transportation cost of GB gas to Ireland will increase by c.**5%** (in real terms (i.e. adjusted for inflation)). This increase in tariffs is mainly due to increases in shrinkage costs and changes in how capacity is booked. The higher shrinkage costs are associated with rises in CO_2 and gas commodity costs. As regards to changes in booking behaviours, there has been a reduction in the bookings of more expensive daily capacity products at Exit. This has the effect of reducing revenue recovery and therefore places upward pressure on Exit tariffs.

Table 2 shows the tariffs for 21/22 relative to those in recent years (in nominal terms (i.e. without adjusting for inflation)). Tariff costs have increased in the last two years, mainly due to the cost of shrinkage[4] moving into the allowed revenue. Despite these increases, due to reductions in the previous three years, the transportation cost of GB gas is similar to 2016/17 and 2017/18 levels.

Table 2: Recent cost of transportation for GB gas (nominal)

	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Capacity – €/peak MWh	788.605	761.263	715.864	669.00	722.44	767.59

[2] "Firm" means gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator.
[3] This is composed of two elements; one to remunerate the transmission services revenue of GNI (€130.44) plus a Corrib Linkline Element (€503.32), which will remunerate the revenues relating to the Corrib Linkline (Corrib Partners).
[4] Shrinkage gas includes own use gas (OUG) and unaccounted for gas (UAG). In 2020/21 shrinkage costs moved into the allowed revenue and are therefore recovered through tariffs. Previously, 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 was a movement of costs, not an increase in overall costs, it did not lead to an increase in costs for end customers.

Network tariffs are charged to gas shippers/suppliers. It is up to suppliers whether to pass on these costs to their customers. Currently, the CRU estimates that network tariffs charges (transmission and distribution collectively) make up approximately 31% of a residential customer's bill. The transmission network tariff charge, if fully passed onto gas customers, would equate to a c. 0.5% (or €4) increase (nominal) on an average residential gas customer's annual bill. 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.

As in previous years, the CRU is also publishing, today, the distribution network tariffs. The distribution tariffs are set to decrease (by c. 3.1%). It is estimated that the combined change in transmission and distribution tariffs equates to a <0.1% (or €0.7) increase on an average residential gas customer's annual bill.

In addition, to the Article 29 requirement to publish tariffs, Article 30 of the TAR NC sets out further detailed information that must be published prior to the tariffs coming into force. In previous years, the CRU published this information in a specific Article 30 paper, separate from the transmission tariffs. The Article 30 paper included the mandatory detail of, for example, how the allowed revenue is calculated, and also other more general information on the transmission setting process, with the aim of making the publication a useful guide to transmission tariffs. These papers were published separately because the network code stipulates different publication deadlines. However, this year the CRU has brought forward the publication of the Article 30 paper and amalgamated it with the Article 29 publication. This is to decrease the level of repetition and provide a useful all in one guide to transmission tariffs.

Customer Impact Statement

The CRU is legally responsible for regulating network charges in the natural gas market. The CRU may set the basis for charges for using the transmission system. Our mission is to protect the public interest in water, energy and energy safety.

The tariffs set out in this paper are charged to suppliers for use of Gas Network Ireland's transmission network – this network consists of the larger gas pipes, for example the gas pipes between larger cities and towns. The CRU conducts an annual review of transmission tariffs to ensure that only necessary costs are included in the calculation of these tariffs. This work has now completed and the transmission tariffs to apply from 01 October 2021 to 30 September 2022 are published in this paper.

Transmission network tariffs for 2021/22 are set to increase by c. 5% when compared to the current gas tariffs for 2020/21. A reason for the increase in tariffs is that some of GNI's costs have increased significantly for the upcoming gas year. For example, there has been an increase in the commodity cost of natural gas and CO_2 emissions, which raises GNI's shrinkage (i.e. natural gas it uses to run the compressors) costs. As detailed in a separate publication alongside this paper, distribution tariffs are set to decrease by c. 3.1%.

Network tariffs are charged to gas suppliers and it is a decision for suppliers whether to pass on these costs to their customers.

Currently, the CRU estimates that network tariffs (transmission and distribution collectively) charges make up approximately 31% of a residential customer's bill. The combined transmission and distribution tariffs, if fully passed onto gas customers, would equate to a **<0.1% (or €0.7)** increase on an average residential gas customer's annual bill. 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.

Table of Contents

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 now has a wide range of economic, customer protection and safety responsibilities in energy and water. The CRU's mission is to protect the public interest in Water, Energy and Energy Safety.

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

1.2 Purpose of the Paper

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.

This paper outlines the CRU's decision in relation to the Gas Network Ireland's (GNI) allowed revenues and transmission tariffs that will apply from 01 October 2021 to 30 September 2022. 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).

The calculation of transmission tariffs is based on the Price Control (PC4) (CER/17/260), which established revenues for Transmission over the 5 year period from October 2017 to September 2022.

Previously the two separate papers would have been published on the tariffs and on the Article 30 information. This led to a degree of repetition while also splitting useful transmission tariff information into two papers. This year the CRU has combined these papers to remove any repetition but also to provide 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 2021/22.

The publication of this information is to provide customers with tariff related 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.

- CRU Transmission Revenue Model 2021/22 (CRU/21/058a)
- CRU Corrib Linkline Model (CRU/21/058b)
- GNI's Simplified Transmission Tariff Matrix Model
- Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Decision 2021/22 (CRU/21/049)
- 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)

1.4 Structure of the Paper

This information paper is structured as follows:

- Section 1 provides an introduction and background
- Section 2 background as to the Irish transmission system and how transmission tariffs are calculated;
- Section 3 outlines the way by which tariffs are updated and how the CRU updates allowed revenues on an annual basis;
- Section 4 provides specific information required by Article 30 of the TAR NC;
- Section 5 sets out the transmission tariffs for 2021/22; and,
- Section 6 provides a conclusion.

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[5] (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 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.

[5] 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.

Figure 1 Gas Network Ireland's transmission system

2.3 Transmission Tariff Methodology for Gas

In 2019, in line the European network code on harmonised transmission tariff structures for gas (TAR NC)[6], the CRU completed a review of the methodology for 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

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

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 2021/22 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. It will be updated to reflect the gas tariffs in this paper before they come into effect. 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 3.3. 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.
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.

Following review for efficiency, the CRU has decided to allow GNI an additional €20.0m for pass-through costs. This includes an additional allowance for a 'typical' pass-through cost item, in this case €3.31m for CO_2, €110k for the CRU levy, €43k for safety initiatives, and -€760k for rates. In addition, the CRU has provided an allowance for an extra-over item, i.e. €17.3m for shrinkage[7].

As was the case for gas year 2020/21, 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.[8] For this reason, it is included in the €20.0m pass-through cost allowance. GNI did not seek any other transmission extra-over items for 2021/22. The substantial additional allowances for CO_2 and shrinkage are a result of the increases in the cost of purchasing CO_2 allowances and the commodity cost of natural gas, respectively.

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 2021/22 the CRU closes out the year 2019/20. Having reviewed the actual data for 2019/20, it has been determined that GNI has over recovered for that gas year. The over recovery is €1.95 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:

[7] Shrinkage gas includes own use gas (OUG), which is gas used to operate the network and unaccounted for gas (UAG) (e.g. gas losses). Previously, the transmission business' shrinkage costs were not included in the allowed revenue and were 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 this is not a new cost, it does not increase overall the costs faced by shippers or end customers.

[8] The CRU will review whether shrinkage should continue to be treated as a pass-through cost as part of its Price Control 5 decision.

Rule 1. Any over-recovery up to 105% of allowed revenues is returned in the following gas year (e.g. any 2019/20 k-factor >105% is returned in gas year 2022/23 not gas year 2021/22). 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 2019/20 k-factor >100% & <103% is returned at Euribor +2% and any 2019/20 k-factor >103% & <105% is returned at Euribor +4%)[9]. 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. In this context, there was an over-recovery in excess of the 105% rule in 2018/19 and 2017/18, and some of this money (€11.45m in total) is still to be returned to customers.[10] As the 105% rule limit was not reached by the 2019/20 k-factor (€1.95m), there is scope for this remaining k-factor revenue (€11.45m) to be returned to customers. In accordance with the 105% rule the CRU has returned the maximum amount to customers in gas year 2021/22 while still applying the 105% rule. This results in an additional €6.8m (in addition to the €1.95m) to be returned to customers, resulting in a total k-factor of €8.8m (105% limit). When interest is applied, this results in a total giveback to customers of €9.7m.

The resulting position is that €4.64m[11] (not including interest) is still to be credited to gas customer's next year.

The CRU considered crediting the €4.64m to customers for gas year 2021/22. However, on balance, this was not considered in the customer's best interest. The €4.64m due to be credited next year will assist in offsetting some upward cost pressures that may arise when closing out gas year 2020/21 next year, such as increased CO_2 and gas costs.

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

[9] As per rule 1 any 2019/20 k-factor >105% is credited the following year, with Euribor +4% applied for both years.
[10] This was noted in Section 3.3.2 of CRU/20/097.
[11] €11.45m - €6.8m

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 2021/22, GNI has analysed recent trends and then applied these learnings to the elements it typically draws from 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 in certain customer categories, particularly in the non-daily metered (NDM) industrial & commercial sector. However, since then, demand has begun to recover and is broadly in line with expectations with seasonal demand.

3.3.3.1 Assumptions

The forecast demands for 2021/22 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[12]. 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 5.3. The value of these capacity products is converted into an annual value. In this way the forecast bookings are "annualised".[13]
Power generation	GNI's demand assumptions are based on Eirgrid's 2020-2029 Generation Capacity Statement (GCS) published in August 2020. Power demand is based on Eirgrid's Median Electricity Demand scenario. Adjustment applied to 2021/22 electricity forecast based on differences between forecast and actual electricity demand to date. The Power sector is expected to increase demand relative to the

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

Assumption	Description
	2020/21 demands due to overall growth in the electricity sector. However, due to decreased booking of daily capacity, the overall annualised capacity bookings are lower.
Daily Metered (DM) Industrial & Commercial (I/C)	The LDM & DM sector is expected to increase its level of capacity bookings relative to the 2020/21 tariff demands. This reflects recent increased demand in the sector and strong GDP growth forecasts (4.67% for gas year 2021/22).
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 increased in 2021/22 relative to the 2020/21 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.

3.3.3.2 Demand forecasts

Table 3.2 and Table 3.3 below present GNI's transmission network demand forecasts for gas year 2021/22. For context, these forecasts are presented alongside GNI's actual demands for 2019/20, the 2020/21 forecast for tariff setting and GNI's most up to date forecast for 2020/21. Highlighting the forecast demands for the upcoming gas year, against the demands forecast when setting the tariffs last year is particularly useful, as higher/lower demand relative to last year will lead to upward/downward pressure for the upcoming gas year.

Table 3.2: Transmission commodity demand forecast summary - MWh

Demand	19/20 actual demand	**20/21 tariff forecast**	20/21 updated forecast		**21/22 demand forecast**	Variation vs 19/20	**Variation vs 20/21 tariff**	Variation vs 20/21 update
Entry Commodity	59,927	**57,202**	58,410		**61,335**	2%	**7%**	5%
Exit Commodity	58,467	**55,869**	56,346		**59,904**	2%	**7%**	6%

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.

Table 3.3: Transmission capacity demand forecast summary - MWh

	19/20 actual demand	**20/21 tariff forecast**	20/21 updated forecast		**21/22 demand forecast**	Variation vs 19/20	**Variation vs 20/21 tariff**	Variation vs 20/21 update
Bellanaboy Entry	65,114	***58,646***	55,902		***44,705***	-31%	**-24%**	-20%
Moffat Entry	145,137	***161,390***	167,123		***183,316***	26%	**14%**	10%
WA[14] Total Entry Capacity	216,786	**220,061**	223,025		**228,059**	5%	**4%**	2%
WA Total Exit Capacity	281,752	**291,425**	281,717		**282,171**	0%	**-3%**	0%

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

For the forthcoming year, transmission commodity forecasts are 2% higher (entry and exit) than the actual (outturn) commodity demand for 2019/20 and 7% (entry) and 7% (exit) higher than the 2020/21 commodity forecast for tariff setting. The increase in commodity demand is mostly driven by increases in gas demand in the power generation and daily metered (DM) industrial/commercial (I/C) sector. The increase in power generation demand reflects the increase in electricity demand, while the increase in DM I&C demand reflects strong performance in the technology and pharmaceutical sectors and strong GDP growth forecasts.

In terms of capacity, GNI's forecasted weighted annualised (WA) Exit capacity demand for 2021/22 is similar to the outturn for 2019/20 and 3% lower than the 2020/21 capacity forecast for tariff setting. Although there is increased commodity demand in the power generation sector, this is not reflected in WA capacity bookings relative to 2020/21 tariff setting, due to decreased booking of daily capacity by this sector, which has been observed in gas year 2020/21. The decrease in WA capacity demand at Exit puts some upward pressure on Exit tariffs.

GNI's forecasted weighted annualised Entry capacity is 5% higher than the outturn for 2019/20 and 2% higher than the 2020/21 capacity forecast for tariff setting. The increase in capacity forecasts at Entry reflects the overall trend of increasing gas commodity demand. However, unlike the Exit capacity forecast, this trend is not offset by a decrease in daily capacity bookings. This may be reasonably associated with the availability of secondary capacity trading at Entry, which provides more options to adjust capacity bookings than for Exit. In terms of the source of supply, Entry supply continues to move to the more expensive Moffat Entry point as Corrib production declines, resulting in greater revenue recovery by GNI. GNI's forecasted weighted

[14] 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.

annualised Entry capacity at Moffat is 26% higher than the outturn for 2019/20 and 14% higher than the 2020/21 capacity forecast for tariff setting. The increase in WA capacity demand at Entry puts some downward pressure on Entry tariffs.

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 2021 – 30 September 2022). 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 2021/22 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

<table>
<tr><th>TAR NC Article</th><th>Description</th><th>Period</th><th colspan="2">Detail</th></tr>
<tr><td>Art. 30 (1)(a)</td><td>Information on parameters used in the reference price methodology that are related to the technical characteristics of the transmission systems</td><td>2021/22</td><td colspan="2">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.</td></tr>
<tr><td>Art. 30 (1)(b)(i)</td><td>Allowed revenue</td><td>2021/22</td><td colspan="2">€212.77m in transmission services revenue and €97k in non-transmission services revenue (21/22 monies).[15]</td></tr>
<tr><td>Art. 30 (1)(b)(ii)</td><td>Changes in allowed revenue</td><td>2020/21 – 2021/22</td><td colspan="2">Increase in allowed revenue by 8%, nominal, (6.7%, real) from gas year 2020/21 to 2021/22. 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.</td></tr>
<tr><td rowspan="4">Art. 30 (1)(b)(iii)(1)</td><td rowspan="4">Asset types and their aggregated value</td><td rowspan="4">At start of current regulatory period –</td><td>Asset type</td><td>Net book value (15/16 monies)</td></tr>
<tr><td>Pipelines/AGIs (incl. GTTW)</td><td>€1246.4</td></tr>
<tr><td>Land</td><td>€1.9m</td></tr>
<tr><td>Equipment</td><td>€19.2m</td></tr>
</table>

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

TAR NC Article	Description	Period	Detail		
		01.10.2017	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.		
Art. 30 (1)(b)(iii)(3)(a)	Initial asset valuation methodology	n/a	Acquisition cost (historic 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

TAR NC Article	Description	Period	Detail		
			Buildings	40 years	€0.8m
Art. 30 (1)(b)(iii)(4)	Operational expenditures	2021/22	€77.61m + €20.00m additional costs set out in section 3.3.1 (21/22 monies)		
Art. 30 (1)(b)(iii)(5)	Incentive mechanisms and efficiency targets	2017/18-2021/22	Capex and opex incentives[16], 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[17]		
Art. 30 (1)(b)(iv)	Transmission services revenue	2021/22	€212.77m (21/22 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		
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. 19/20)	2019/20	Actual revenue recovered was €177.31m 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 (21/22) and (iii) incentives.	2019/20	See section 3.3.2 for explanation. (i) €1.95m for 19/20, total is €8.77m, (ii) Reduced allowed revenue by €9.7m, (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	2021/22	See Table 5.1		
Art. 30 (1)(c)(ii)	Non-transmission tariffs	2021/22	The Corrib Linkline Element of the Bellanaboy tariff is considered a non-		

[16] See Section 7 of CER/17/260 for further detail regarding the incentives applied to the TSO.
[17] See 'Inflation' and 'Indexation' tab of CRU/21/058a Transmission revenue model 2021/22 for further detail.

<table>
<tr><th>TAR NC Article</th><th>Description</th><th>Period</th><th colspan="5">Detail</th></tr>
<tr><td></td><td></td><td></td><td colspan="5">transmission tariff[18] under TAR NC. See Table 5.1</td></tr>
<tr><td>Art. 30 (1)(c)(iii)</td><td>Reference prices for other points than interconnection points</td><td>2021/22</td><td colspan="5">See Table 5.1</td></tr>
<tr><td>Art. 30 (2)(a)(i)</td><td>Information about tariff changes and trends</td><td>2020/21 - 2021/22</td><td colspan="5">See Appendix A for the difference in tariffs and Section 3 for an explanation of this difference.</td></tr>
<tr><td>Art. 30 (2)(a)(ii)</td><td>Information about tariff changes and trends</td><td>2017/18 - 2021/22</td><td colspan="5">A simplified model is available on GNI's website at the following link. This allows the calculation of the possible evolution of tariffs.</td></tr>
<tr><td>Art. 30 (2)(b)</td><td>A simplified tariff model</td><td>2021/22</td><td colspan="5">A simplified model is available on GNI's website link.</td></tr>
<tr><td rowspan="5">Art. 30 (3)</td><td rowspan="5">Information on the amount of forecasted contracted capacity and the forecasted quantity of the gas flow on non-relevant points</td><td rowspan="5">2021/22</td><td>Market Segment</td><td>Unit</td><td>Forecasted Contracted Capacity[19]</td><td>Unit</td><td>Forecasted Gas Flow</td></tr>
<tr><td>Power gen</td><td>MWh/d</td><td>140,161</td><td>GWh/y</td><td>34,390</td></tr>
<tr><td>DM</td><td>MWh/d</td><td>45,193</td><td>GWh/y</td><td>12,934</td></tr>
<tr><td>NDM</td><td>MWh/d</td><td>96,606</td><td>GWh/y</td><td>12,524</td></tr>
<tr><td>CNG</td><td>MWh/d</td><td>211</td><td>GWh/y</td><td>57</td></tr>
</table>

[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 CRU Decision on Transmission Tariffs for 2021/22

5.1 Transmission tariffs for 2021/22

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 2021 to 30 September 2022 based on a revenue of €212.77m (2021/22 monies) are set out below.

Table 5.1: Transmission tariffs for 2021/22

	Bellanaboy entry	**RNG entry[20]**	**Moffat (IP) entry**	**Domestic exit**	**Gormanston (IP) exit**
Firm[21] capacity - €/peak day MWh	633.76[22]	104.32	312.89	454.70	432.40
Commodity - €/MWh	0.114			0.238	

With these updated tariffs, the transportation cost of GB gas[23] to Ireland will increase by c.**5%** (in real terms (i.e. adjusted for inflation)). This increase in tariffs is mainly due to increases in shrinkage costs and changes in how capacity is booked. The higher shrinkage costs are associated with rises in CO_2 and gas commodity costs. As regards to changes in booking behaviours, there has been a reduction in the bookings of more expensive daily capacity products at Exit. This has the effect of reducing revenue recovery and therefore places upward pressure on Exit tariffs.

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[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 (€130.44) plus a Corrib Linkline Element (€503.32), which will remunerate the revenues relating to the Corrib Linkline (Corrib Partners).

[23] The transportation cost of GB gas (Moffat entry capacity tariff + domestic exit capacity tariff) 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.

For comparison, Table 5.2 below provides the 2021/22 transportation cost of GB gas relative to those in recent years (in nominal terms (i.e. without adjusting for inflation)). Tariff costs have increased in the last two years, mainly due to the cost of shrinkage[24] moving into the allowed revenue. Despite these increases, due to reductions in the previous three years, the cost of transportation of GB gas is similar to 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**	**2021/22**
Capacity – €/peak MWh	788.605	761.263	715.864	669.00	722.44	767.59

5.2 Impact on a residential customer's bill

Network tariffs are charged to gas shippers/suppliers. It is up to suppliers whether to pass on these costs to their customers. Currently, the CRU estimates that network tariffs charges (transmission and distribution collectively) make up approximately 31% of a residential customer's bill. The transmission network tariff charge, if fully passed onto gas customers, would equate to a c. 0.5% (or €4) increase (nominal) on an average residential gas customer's annual bill. 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.

As in previous years, the CRU is also publishing, today, the distribution network tariffs. The distribution tariffs are set to decrease (by c. 3.1%). It is estimated that the combined change in transmission and distribution tariffs equates to a <0.1% (or €0.7) increase on an average residential gas customer's annual bill.

5.3 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

[24] 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.

seasonal factor profile for gas year 2021/22. The CRU decided to not to change the profile for gas year 2021/22 as set out in its annual tariff network code Article 28 paper (CRU/21/049).

Table 5.3: Multiplier and seasonal factor profiles[25]

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%

5.4 Virtual Reverse Tariff 2021/22

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.[26] 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.

[25] 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.

[26] 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.

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 adjustment for gas year 2021/22 as set out in its annual tariff network code Article 28 paper (CRU/21/049).

Table 5.4: Virtual reverse flow (VRF) tariffs for 2021/22

	Gormanston (IP) VRF entry	Moffat (IP) VRF exit
Capacity – €/peak day MWh	74.58	295.31
Commodity - €/MWh	0.114	0.238

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 2021/22 transmission tariffs. These tariffs will take effect from 01 October 2021.

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 2021/22

GNI Transmission Tariffs for 2021/22			Published Tariffs		
	2021/22 Tariffs		2019/20 Tariffs	2020/21 Tariffs	% Change
	€	(2021/22 Monies)	€	€	Nominal
Exit					from 2020/21
capacity	**454.697**	per peak day MWh	367.658	407.634	11.5%
commodity	**0.238**	per MWh	0.216	0.236	0.7%
Gormanston Exit					
capacity	**432.400**	per peak day MWh	345.341	385.366	12.2%
commodity	**0.238**	per MWh	0.216	0.236	0.7%
Moffat Entry					
capacity	**312.893**	per peak day MWh	301.345	314.810	-0.6%
commodity	**0.114**	per MWh	0.103	0.114	0.7%
Bellanaboy Entry					
capacity	**633.755**	per peak day MWh	619.442	629.993	0.6%
commodity	**0.114**	per MWh	0.103	0.114	0.7%
RNG Entry					
capacity	**104.323**	per peak day MWh	92.775	106.239	-1.8%
commodity	**0.114**	per MWh	0.103	0.114	0.7%
Gormanston VRF Entry					
capacity	**74.580**	per peak day MWh	65.110	76.151	-2.1%
commodity	**0.114**	per MWh	0.103	0.114	0.7%
Moffat VRF Exit					
capacity	**295.315**	per peak day MWh	250.044	270.857	9.0%
commodity	**0.238**	per MWh	0.216	0.236	0.7%
Illustrative Transmission Transportation Costs					
	€		€	€	%
Transmission Transportation Cost of UK Gas					
capacity	**767.591**	per peak day MWh	669.003	722.443	6.2%
commodity	**0.352**	per MWh	0.319	0.350	0.7%
Transmission Transportation Cost of Bellanaboy Gas					
capacity	**1,088.453**	per peak day MWh	987.099	1,037.627	4.9%
commodity	**0.352**	per MWh	0.319	0.350	0.7%
Transmission Transportation Cost of RNG					
capacity	**559.020**	per peak day MWh	460.432	513.873	8.8%
commodity	**0.352**	per MWh	0.319	0.350	0.7%