



An Coimisiún
um Rialáil Fóntas
**Commission for
Regulation of Utilities**

An Coimisiún um Rialáil Fóntas
Commission for Regulation of Utilities

Harmonised Transmission Tariff Methodology for Gas

Decision Paper – Art. 26 & 28

Decision Paper

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|-------------------|------------|------------------------|------------|----------------------|-----|
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Executive Summary

Gas Networks Ireland owns and operates the gas transmission network. Regulated tariffs apply for the use of this system. The CRU sets the methodology for how these tariffs are calculated. As required by the European Tariff Network Code, the CRU has consulted upon the tariff setting methodology.

Review process

The CRU commenced its review of the transmission tariff methodology in 2018. The review has been guided by criteria set out in the Tariff Network Code. Those criteria are set out in Art. 7 of TAR NC¹, and can be summarised as (a) transparency, (b) cost-reflectivity, (c) non-discrimination and cross-subsidisation, (d) volume risk, and (e) cross-border trade.² In addition, the CRU also considered (1) predictability, (2) stability and (3) the effect on equity and the promotion of effective competition. These additional criteria ensure that the specifics of the Irish system are duly considered and that the best outcomes for the Irish consumer are achieved. The CRU considers this approach in full compliance with the requirements and spirit of the Network Code.

The CRU published a consultation paper on the tariff methodology (CRU/18/247) in December 2018. Before publishing the consultation paper, the CRU engaged with industry and wider stakeholders through a Networks Tariff Liaison Group (NTLG)³.

As part of the review process, as required by the Tariff Network Code, ACER also provided analysis of the CRU consultation paper. The CRU would like to thank all parties for their input into this process. Their comments have been fully considered in making the decisions set out in this decision paper.

Key Decisions

The outcome of the review and the decisions made by the CRU are now discussed. The decisions start with the overall tariff methodology to be applied. Specific aspects of the tariff setting methodology are then set out.

¹ See Section 3.4.2. of the consultation paper for further detail.

² Compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Art. 13 of Regulation (EC) 715/2009.

³ The purpose of the NTLG was to provide a peer review and analysis of information to ensure that the tariff methodology was considered in the context of the Irish gas market.

Reference price methodology

In 2015 the CRU approved a Matrix reference price methodology (RPM). In the consultation paper the CRU proposed to continue to use the Matrix RPM. This was on the basis that the CRU considered the Matrix RPM to be suited to the characteristics of the Irish gas market while being fully compliant with the principles and the criteria of the TAR NC. A clear majority of respondents agreed with the CRU's proposal to continue to apply the Matrix RPM. In addition, ACER, in its analysis of the CRU's consultation, considered that the Matrix RPM was overall compliant with the principle of cost-reflectivity. With its continued suitability to the specifics of the Irish network and its compliance with the Network Code, the CRU has decided to continue to apply the matrix RPM.

CRU Decision

1. The CRU has decided to continue to apply the Matrix RPM for the calculation of transmission tariffs.

Shrinkage charges

Shrinkage gas is made up of both own use gas (i.e. fuel gas used to operate compressors) and unaccounted for gas. Currently, the costs associated with shrinkage gas are not recovered through tariffs, but through a separate charge to shippers. In the consultation paper the CRU proposed that shrinkage is classified as a transmission service, resulting in cost-recovery through tariffs.⁴

Some respondents were in favour of the CRU's proposal to class shrinkage as a transmission service and some were not. The CRU continues to be of the view that shrinkage is a transmission service. In this regard, the CRU considers that all network users derive a benefit of the pressures being maintained throughout the system, regardless of location. In addition, shrinkage meets the criteria to be treated as a transmission service as set out in Art. 4.1 of the TAR NC. ACER in its analysis, agreed with this.

In relation to concerns over the practical timelines required to incorporate shrinkage into transmission revenues (e.g. changes to TSO billing processes, code of operations), the CRU has decided to incorporate shrinkage into transmission services revenue in 2020/21 and not 2019/20.

⁴ The recovery of shrinkage costs under the transmission service tariff arrangements presents an important element of the justification for a 90/10 capacity/commodity split. While shrinkage costs are not explicitly recovered through the commodity charge, given that the commodity charge is expected to cover costs associated with the flow of gas, such as shrinkage costs, the CRU refers to these costs as being included within the commodity charge.

During 2019/20, GNI will be required to provide shadow reporting⁵ on shrinkage costs for the gas year 2019/20 (as if they were already incorporated into the transmission revenues). In this transition period, the CRU will further engage with Shippers and GNI on additional shrinkage reporting arrangements. This decision ensures a smooth transition to the new charging arrangement and no loss of transparency for stakeholders.

CRU Decision

3. The CRU has decided that starting in the gas year 2020/21 shrinkage will be classified as a transmission service.

Entry/exit split

The entry/exit split allocates the portion of allowed/transmission services revenue to be recovered from entry and exit charges. In the consultation paper, the CRU proposed that an entry/exit split of 33:67 be maintained.

The CRU is of the view that continuing with the 33:67 entry/exit split is in the best interest of gas customers as it maintains regulatory stability. The clear majority of respondents favoured the proposal. ACER also highlighted no compliance issues with the implementation of this split.

As a result of the above, the CRU has decided to continue to apply a 33:67 entry/exit split.

CRU Decision

4. The CRU has decided to continue to apply a 33:67 entry/exit split.

Capacity/commodity split

The capacity/commodity split allocates the portion of transmission services revenue to be recovered from capacity and commodity charges. In the consultation paper the CRU proposed that a capacity/commodity split of 90:10 be maintained. The clear majority of respondents favoured this proposal. ACER, in its analysis also considered that the 90:10 split was in line with the requirements of the TAR NC.

With the inclusion of shrinkage costs into transmission revenues (as outlined earlier), the CRU is

⁵ Reporting to shippers on the costs, as if these costs were included in the transmission services revenue in 2019/20.

of the view that a 10% commodity element best reflects the approximate costs associated with the quantity of gas flowed.⁶ Based on its cost reflectivity and respondents' comments, the CRU has decided to apply a 90:10 capacity/commodity split.

CRU Decision

5. The CRU has decided to continue to apply a 90:10 capacity/commodity split.

Expansion constants and annuitisation factors

The expansion constants are applied within the Matrix RPM to provide a forward-looking cost signal. This is a key element of the CRU's decision in 2015 to apply the Matrix RPM. The cost signal is based on the cost to provide additional incremental capacity at points on the network – in other words, how much it would cost to expand the network. However, the expansion constants are not annualised and do not cover pipeline operating costs. In order to reflect these costs, an annuitisation factor is applied.

In the consultation paper the CRU proposed updating the expansion constants and annuitisation factor so that they use the most up to date information. The results were that the wet expansion constant rose from €8,757 GWh/d/km to €8,783 GWh/d/km, and that the dry expansion constant decreased from €7,874 GWh/d/km to €7,810 GWh/d/km. The annuitisation factor reduced from 10.5% to 9.8%.

The majority of respondents were supportive of the CRU's proposal. The CRU continues to be of the view that periodically updating the expansion constants and annuitisation factor to reflect the up to date information (i.e. gas prices) is appropriate as it increases the cost-reflectivity of these components of the Matrix RPM, and therefore the cost signals that the Matrix RPM sends.

Given the above, the CRU has decided to apply the updated expansion constants (wet: €8,783 per GWh/d/km, dry: €7,810 per GWh/d/km) and annuitisation factor (9.8%).

⁶ In the consultation paper the CRU stated that it is estimated that the cost of shrinkage in 2018/19 will be approximately €14.7m. If this was to be included in the 2018/19 transmission services revenue it would make up approximately 7.5% of the transmission services revenue, thereby making the proposed 10% commodity allocation much more cost-reflective. The 2.5% difference recovers other costs related to the quantity of gas flowed e.g. CO₂ emissions. Also, there are less quantifiable costs captured here such wear and tear on the compressors due to batch flows.

CRU Decision

6. The CRU has decided to apply expansion constants of:

wet: €8,783 per GWh/d/km, **dry:** €7,810 per GWh/d/km.

7. The CRU has decided to apply an annuitisation factor of 9.8%.

LNG discounts

The TAR NC allows for, but does not require, the application of a discount to the tariff at an entry point from an LNG facility for the purposes of increasing security of supply. There are currently no LNG facilities in Ireland. However, there are LNG projects that could potentially be developed in the future. In the consultation paper the CRU proposed to not apply LNG discounts at this time, but that it would continue to consider the relative merits of the provision of LNG discounts on a project-by-project basis against a number of non-binding conditions, which were detailed in the paper.

Most respondents considered that currently there is no need for LNG discounts. However, responses were more mixed when it came to whether LNG discounts should be considered in the future, with some respondents raising concerns that leaving the door open to future discounts raises uncertainty. The CRU continues to be of the view that it is in the public interest to continue to consider the case for LNG discounts as new information becomes available. To this end the CRU had decided that proposed LNG projects can apply for a potential discount. The CRU has set out non-binding criteria against which applications for discounts would be assessed and timelines for submissions (the CRU must be notified of an application 18 months before the start of the gas year in which discounts are sought, with a formal application 12 months before tariffs are set for that year). This follows the proposal in the consultation, which ACER confirmed in its analysis as being in line with the TAR NC requirements.

CRU Decision

9. The CRU has decided that potential LNG terminals can apply for a discount.

Applications for discounts will be reviewed on a case by case basis.

10. The CRU has decided to assess applications for LNG discounts against the non-binding criteria set out in Section 3.8.3, and for that assessment to follow the process set out within the same section.

Renewable natural gas (RNG) transmission entry point tariff

Ireland has the potential for the development of a number of RNG⁷ injection facilities in the coming years, in line with GNI's strategic plan to achieve 20% Renewable Natural Gas on the network by 2030. It is therefore important to consider the tariff arrangements which will apply to these new types of entry over the forthcoming tariff period. In the consultation paper the CRU proposed a single tariff for RNG entry points based on a single 'notional entry point' located on the Irish gas system. The CRU considered two options for the location of the notional point. The first was based on the average of three geographically dispersed locations of Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway), and the second was a location that is close to a demand centre.

The CRU continues to be of the view that a single notional RNG entry point is in the best interest of the Irish gas market currently as it meets the CRU's principles of simplicity, stability and providing investor certainty, which are important for a nascent industry such as RNG. A clear majority of respondents favour this proposal. ACER, in its analysis of the CRU's consultation also considered that this approach is allowed by the TAR NC.

With regard to the location of the single notional entry point, there was a mixed response from respondents. The CRU has come to the decision that the most appropriate approach at this time is for the single notional RNG entry point to be a geographic average of three points on the network. The CRU is of the view that this approach is more cost-reflective than the alternative (locating close to a demand centre) as it better reflects the likely location of RNG facilities. This produces a RNG entry tariff in the year 2019/20 of €93/MWh, relative to a Moffat entry tariff of €301/MWh.

The CRU is of the view that the single notional point based on an average of geographically dispersed points will support the development of this industry in its infancy by meeting the principles of simplicity, stability and providing investor certainty. In addition, it helps the CRU meet its own strategic priority of delivering sustainable, low-carbon solutions with well-regulated markets and networks in the public's interest. The CRU will continue to consider how it can implement the appropriate policies that will allow the RNG industry to develop effectively, as it has done to date through its RNG connections policy (CRU/18/089) and the recent Code Modification proposal AO94.

The CRU will assess the transmission tariffing arrangement for RNG again as part of its periodic (five-year) Art. 26 consultation in accordance with TAR NC.

⁷ Referred to as "biogas" in the consultation paper.

CRU Decision

11. The CRU has decided to apply a single notional RNG entry point approach for RNG.

12. The CRU has decided that this single RNG entry point will be based on an average of the geographically dispersed locations of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway).

Virtual reverse flow

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 ROI via Moffat and into ROI via Gormanston.⁸ VRF is a day-ahead interruptible product.

The CRU has signalled for a number of years that the current interim administrative charge for VRF would be replaced with an appropriate tariff. In the consultation it was proposed to apply a tariff based on the principles and the requirements of the TAR NC for standard interruptible products. The CRU proposed that the Moffat exit VRF tariff would be based on the firm Moffat exit tariff and the Gormanston VRF product would be based on the firm Gormanston entry tariff.

ACER agreed with the CRU's proposed approach to setting a VRF tariff in principle. However, other responses to the CRU's consultation were mixed. Some respondents were supportive of the proposal and other respondents were in favour of the proposal in principle but took issue with certain elements of the calculation of the tariff. However, almost half of respondents who commented on the issue were opposed to the VRF proposal on grounds such as cost-reflectivity. Those respondents requested charges that would allow for cheaper use of VRF.

The CRU remains of the view that it is appropriate to use the TAR NC principles to set the tariffs for the Moffat and Gormanston VRF products. The CRU considers that this will provide transparency and predictability to users of the service.

The CRU recognises that the tariffs proposed in the consultation were significantly higher than the current administrative charge for use of VRF. However, the CRU has taken measures to ensure that the VRF tariffs reflect the interruptible nature of the product and to ensure that the VRF tariffs are lower than their forward flow equivalents to help avoid cross-border flow distortions. This was done by applying appropriate A factors and Pro Factors, as allowed for under the TAR NC. Setting the tariff in this way is a pragmatic approach based on the balance of information available and is

⁸ 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.

aimed to ensure utilisation of the VRF service. This results in a Gormanston VRF reference price of €65/MWh and a Moffat VRF reference price of €250/MWh. The CRU has also decided that as the VRF service is only available as a daily product, there should be no short-term multiplier applied. However we do not consider that the same rationale can be applied to the application of seasonal factors. To maintain consistency with other supply points within the single entry/exit system, we therefore retain seasonal factors for the VRF tariff.

Overall the CRU has reached what it considers to be a balanced position, which is compliant with the requirements of the TAR NC. At the same time, it should be noted that it is difficult to predict all impacts of a proposed tariff. The CRU therefore considers it important that, to the extent possible, the impacts of the new VRF tariff should be assessed. The CRU will work with the Code Modification Forum to establish the factors that could be practically considered in this assessment; including the impact on the IBP.

CRU Decision

14. The CRU has decided to calculate a tariff for Moffat VRF and Gormanston VRF based on the TAR NC principles and requirements for standard interruptible capacity products, as set out in Section 3.11.4.

Multipliers and seasonal factors

Multipliers and seasonal factors are applied to the reference prices to set the tariffs for non-yearly capacity products. In the consultation paper the CRU considered two approaches to calculating the multipliers and seasonal factors in the context of the principles set out in Art. 28 and the characteristics of the Irish gas market. The CRU proposed a minor adjustment to the monthly multipliers so that their sum comes within the bounds of the 1.5 limit as set out in TAR NC (this also leads to a reduction of the daily multiplier from 2.89 to 2.79). In addition, the CRU proposed reducing the quarterly multiplier to 1.35, to incentivise use of the product.

The CRU continues to be of the view that the most appropriate approach for the Irish gas market is the approach that reduces the current monthly multipliers so that their sum is at the bounds of the 1.5 limit as set out in the TAR NC. The CRU considers that this approach rather than the prescriptive TAR NC calculation is more consistent with the requirements of Art. 28, such as facilitating efficient utilisation of infrastructure. In addition, implementing the TAR NC methodology, rather than one based on historic peak days, would lead to a significant change in the seasonal factor profile and considering the responses from stakeholders such a significant change at this time would not be preferred as it creates instability.

The CRU continues to be of the view that reducing the quarterly multiplier to 1.35, to incentivise its

use, is appropriate and this is further evidenced by the clear majority of respondents favouring this proposal.

As a result of the above, the CRU has decided to set the monthly multipliers so that their sum is 1.5 times the annual product and to set the quarterly multiplier so that it is 1.35 times the same.

CRU Decision

15. The CRU has decided on multipliers and seasonal factors, which when combined lead to a price equal to percentage values of the annual product as follows:

| <u>Month</u> | <u>Quarterly %</u> | <u>Monthly %</u> | <u>Daily %</u> |
|--------------|--------------------|------------------|----------------|
| 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% |
| <i>Total</i> | <i>135.0%</i> | <i>150.0%</i> | <i>279.44%</i> |

Next steps

The calculation of gas transmission tariffs for Gas Year 2019/20 incorporated the decisions set out in this paper. The CRU published the gas transmission tariffs for the 2019/20 gas year in CRU 19/061⁹. The transmission tariff model for 2019/20 will be made available alongside CRU 19/061 on the CRU's website as soon as possible. Until that time, the 2019/20 transmission tariff model is available from the CRU on request. Interested parties should contact gasnetworks@cru.ie to be sent a copy of the 2019/20 transmission tariff model.

⁹https://www.cru.ie/document_group/copy-of-gas-networks-ireland-allowed-revenues-and-gas-transmission-tariffs/

Public/ Customer Impact Statement

The Commission for Regulation of Utilities (CRU) is the independent economic regulator for the natural gas, electricity and water sectors in Ireland. Our mission is to protect the public interest in water, energy and energy safety.

Gas Networks Ireland (GNI) owns and operates the gas network that supplies natural gas to customers in Ireland. The CRU is legally responsible for regulating the transmission and distribution network tariffs that GNI charges to users of the network. The CRU does so in the best interests of the consumer. These tariffs allow GNI, as the network operator, to recover the allowed revenue set by the CRU to operate the network in a safe and efficient manner. In this paper the CRU is consulting on several components of the tariff structure such as the reference price methodology that is used in the calculation of tariffs for use of the transmission network.

Different approaches to tariff setting for gas transmission services among European Union (EU) Member States makes using EU gas transmission networks more complex for network users, leading to inefficient use and development of the transmission networks, and, potentially, to inefficient gas trades. This can result in increased costs for the gas consumer. The EU network code on harmonised transmission tariff structures for gas (TAR NC)¹⁰ was published by the EU Commission, aiming to overcome such issues.

The CRU is now publishing its decision paper on the harmonised transmission tariff methodology for gas having considered responses from stakeholders and ACER's analysis of the CRU's consultation. With this decision the CRU aims to ensure that a harmonised transmission tariff methodology exists in Ireland and that the Irish transmission tariff methodology continues to appropriately reflect the unique characteristics of the Irish gas network and market, to the benefit of gas consumers.

The decisions reached do not significantly rework how transmission tariffs are calculated but seek to further refine certain aspects of the calculation so that a harmonised transmission tariff methodology exists in Ireland to the benefit of gas consumers. The decisions in this paper will lead to an increase in transmission tariffs. This is primarily due to the inclusion of shrinkage into the tariffs. However, this should have little impact on customers as they already pay for shrinkage. Excluding the impact of shrinkage, it is estimated that the recommendations set out in this memo and the TAR NC decision paper would lead to a minimal change in domestic customers' bills of

¹⁰ Establishing a network code on harmonised transmission tariff structures for gas (Commission Regulation (EU) 2017/460).

minus 0.04% or €0.28.

Table of Contents

| | |
|--|-----------|
| Executive Summary | 1 |
| Public/ Customer Impact Statement | 10 |
| Table of Contents | 12 |
| Glossary of Abbreviations and Terms | 15 |
| 1 Introduction | 18 |
| 1.1 The Commission for Regulation of Utilities | 18 |
| 1.2 Background | 18 |
| 1.2.1 Allowed revenue and tariff setting | 18 |
| 1.2.2 Development of the current methodology | 19 |
| 1.2.3 Review of the methodology as required by the European Gas Network Code | 20 |
| 1.2.4 CRU review process | 20 |
| 1.3 Purpose of this paper | 21 |
| 1.4 Related Documents | 22 |
| 1.5 Structure of Paper | 23 |
| 2 Irish Transmission System and Gas Market | 24 |
| 2.1 Introduction | 24 |
| 2.2 Irish transmission network topology and gas supply | 24 |
| 2.3 ROI Gas Market | 26 |
| 2.4 Potential future supply scenarios | 27 |
| 3 CRU Decisions | 30 |
| 3.1 Introduction | 30 |
| 3.2 Reference price methodology | 30 |
| 3.2.1 Introduction | 30 |
| 3.2.2 Consultation proposal and comments | 30 |
| 3.2.3 Response to comments | 32 |
| 3.2.4 Decision | 38 |
| 3.3 Transmission & non-transmission services | 38 |
| 3.3.1 Introduction | 38 |
| 3.3.2 Consultation proposal and comments | 39 |
| 3.3.3 Decision | 39 |
| 3.4 Shrinkage | 40 |

| | |
|--|-----------|
| 3.4.1 Introduction | 40 |
| 3.4.2 Consultation proposal and comments | 40 |
| 3.4.3 Response to comments..... | 43 |
| 3.4.4 Decision | 45 |
| 3.5 Entry/Exit split..... | 45 |
| 3.5.1 Introduction | 45 |
| 3.5.2 Consultation paper and comments..... | 46 |
| 3.5.3 Response to comments..... | 46 |
| 3.5.4 Decision..... | 46 |
| 3.6 Capacity/commodity split | 47 |
| 3.6.1 Introduction | 47 |
| 3.6.2 Consultation proposal and comments..... | 47 |
| 3.6.3 Response to comments..... | 48 |
| 3.6.4 Decision..... | 50 |
| 3.7 Expansion constant & annuitisation factor | 50 |
| 3.7.1 Introduction | 50 |
| 3.7.2 Consultation proposal and comments..... | 51 |
| 3.7.3 Response to comments..... | 52 |
| 3.7.4 Decision..... | 54 |
| 3.8 Discounts | 55 |
| 3.8.1 Introduction | 55 |
| 3.8.2 Consultation proposal and comments..... | 55 |
| 3.8.3 Decision..... | 57 |
| 3.9 RNG transmission entry tariff..... | 60 |
| 3.9.1 Introduction | 60 |
| 3.9.2 Consultation proposal and comments..... | 60 |
| 3.9.3 Decision..... | 62 |
| 3.10 RNG distribution entry tariff..... | 63 |
| 3.10.1 Introduction | 63 |
| 3.10.2 Consultation proposal and comments..... | 63 |
| 3.10.3 Decision..... | 64 |
| 3.11 Virtual Reverse Flow | 64 |
| 3.11.1 Introduction | 64 |
| 3.11.2 Consultation proposal and comments..... | 65 |
| 3.11.3 Response to comments..... | 69 |
| 3.11.4 Decision..... | 73 |
| 3.12 Multipliers & Seasonal Factors | 75 |
| 3.12.1 Introduction | 75 |
| 3.12.2 Consultation proposal and comments..... | 76 |
| 3.12.3 Decision..... | 79 |
| 4 Summary..... | 81 |
| 4.1 CRU decisions | 81 |
| 4.2 Next steps | 82 |

| | |
|---|-----------|
| A Tariffs for 19/20 Gas Year €/MWh | 83 |
| B ACER recommendations | 85 |
| B.1 Introduction | 85 |
| B.2 Allowed revenue | 85 |
| B.2.1 ACER recommendation..... | 85 |
| B.2.2 CRU Response | 85 |
| B.3 Twynholm transparency | 86 |
| B.3.1 ACER recommendation..... | 86 |
| B.3.2 CRU Response | 86 |
| B.4 Non-transmission services revenue correction | 86 |
| B.4.1 ACER recommendation..... | 86 |
| B.4.2 CRU Response | 86 |
| B.5 Charges outside scope of TAR NC | 87 |
| B.5.1 ACER recommendation..... | 87 |
| B.5.2 CRU Response | 87 |
| C Multipliers and Seasonal Factors | 89 |
| C.1 Multipliers | 89 |
| C.2 Seasonal factors | 89 |

Glossary of Abbreviations and Terms

| Abbreviation | Definition or Meaning |
|---------------|---|
| ACER | Agency for the Cooperation of Energy Regulators |
| Art. | Article |
| CWD | Capacity Weighted Distance |
| CRU | Commission for Regulation of Utilities |
| ENTSOG | European Network of Transmission System Operators for Gas |
| EU | European Union |
| GB | Great Britain |
| GNI | Gas Networks Ireland |
| I/C | Industrial/Commercial |
| IBP | Irish Balancing Point |
| IP | Interconnection Point |
| ISEM | Integrated Single Electricity Market |
| LNG | Liquefied Natural Gas |
| LRMC | Long-Run Marginal Cost |
| NBP | National Balancing Point |
| NI | Northern Ireland |
| PC4 | Price Control 4 |
| ROI | Republic of Ireland |
| RNG | Renewable Natural Gas |
| RPM | Reference Price Methodology |
| TAR NC | Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas |
| TSO | Transmission System Operator |
| UAG | Unaccounted for gas |

| Term | Definition or Meaning |
|--|--|
| Allowed Revenue | The sum of transmission services and non-transmission services revenues that GNI is entitled to recover in a given period as the transmission system operator/owner, as approved by the CRU. |
| Annuitisation factor | The percentage of the expansion constant to reflect the annual remuneration of the cost of and on capital as well as associated operating costs. |
| Renewable Natural Gas or RNG/ RNG | For the purposes of this consultation, RNG means gas produced from renewable non-fossil sources, mostly commonly by anaerobic digestion of biodegradable matter and which is (or will be) prior to such gas being tendered for delivery to the Transportation System purified and upgraded to meet the applicable Entry Specification. |
| Capacity/commodity Split | The apportionment of revenue to be recovered from capacity-based transmission tariffs and commodity-based transmission tariffs. |
| Correction Factor (K-Factor) | An adjustment of the annual revenue for future gas years to rectify over or under recoveries of revenue in a previous gas year. |
| Domestic Exits | Exit Points that are within Ireland, excluding Interconnection Points. |
| Entry/exit split | The apportionment of revenue to be recovered from entry points and exit points. |
| Entry/exit system | A network of high-pressure transmission pipelines which are the basis for the calculation for bringing gas onto the system (entry tariffs) and for taking gas off the system (exit tariffs). |
| Equalisation | A secondary adjustment applied to tariffs across a certain category of network users for the purposes of tariff stability. The result of equalisation is that the same tariff is charged at all the relevant (equalised) points. |
| Expansion constant | A numerical value of expanding the capacity of the system so that one unit of gas can travel over one kilometre. |
| Interconnection Point | A point connecting one entry-exit system to another entry/exit system. |
| Multiplier(s) | Outlines the pricing relationship between non-yearly capacity products and the annual capacity product. |
| Non-transmission services | Regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the TSO. |
| Primary Tariff | The set of tariffs (based on LRMC and distances) which reflect the differentials between the different entry or exit points. |
| Reference Price | The tariff for a firm capacity product with a duration of one year, calculated using the preferred reference price methodology. It should be noted that the reference prices for entry and exit are set separately. |

| | |
|------------------------------------|---|
| Reference Price Methodology | The methodology set or approved by the national regulator in order to calculate the reference price. |
| Rescaling | A secondary adjustment to primary tariffs to recover the transmission services revenue of the GNI. |
| Reserve Prices | The reference price, which is an annual capacity price for a firm product, becomes the basis for the calculation of the auction prices for each of the non-yearly products, known as reserve prices. As there is no auction premium the reserve price is equal to the tariff for each of the capacity products. |
| Seasonal Factors | Allows for variations in the seasonal value of the same standard capacity products and thus creates incentives for the efficient use of the transmission system (e.g. encouraging more gas flows during the summer time). |
| Shrinkage | Shrinkage gas means own use gas and natural gas required to replace Unaccounted for Gas (UAG). Own use gas means natural gas which is used by GNI for the operation of the gas transportation network or any localised part thereof including at compressor stations and/or for pre-heating and venting purposes. UAG means natural gas which is lost or otherwise unaccounted for from the gas transportation network or any localised part thereof. |
| Secondary Adjustment | An adjustment applied to primary tariffs for the purposes of revenue recovery or tariff stability. |
| Transmission services | The regulated services that are provided by the TSO within the entry-exit system for the purpose of transmission. |
| Virtual Reverse Flow (VRF) | VRF is a 'reverse flow' service offered on a virtual basis, at the IPs, to enable gas Shippers to virtually flow gas along a unidirectional pipeline. |

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. The CRU is also the regulator of Ireland's public water and wastewater system.

Under the Gas (Interim) (Regulation) Act, 2002, the CRU is responsible for regulating charges in the natural gas market. Under Section 14 of that Act, the CRU may set the basis for charges for transporting gas through the transmission system. The CRU does so in the best interests of gas consumers. Our goal is to ensure that gas is safely and securely supplied and that the charges are fair and reasonable.

1.2 Background

1.2.1 Allowed revenue and tariff setting

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. A price control sets out the revenues that GNI can collect over a 5-year period. The CRU approves these revenue requirements to ensure only necessary costs are included for the operation, maintenance and development of the gas network in an efficient and safe manner on behalf of gas customers. The current 5-year Price Control period started on 1 October 2017 (PC4). Allowed revenues for the transmission and distribution systems are set out separately. This paper considers the revenues and resulting tariffs of the transmission system.

The allowed revenue for the transmission system is split into transmission services revenue and non-transmission services revenue.¹¹ The transmission services revenue is then inputted to GNI's transmission RPM to calculate the transmission tariffs on an annual basis. The tariffs allow GNI, as the network operator, to recover its transmission services revenue, i.e. to recover the costs of maintaining and operating the gas transmission network.

¹¹ Transmission services are the regulated services offered by GNI, e.g. gas transportation services. These services are paid for by network users through capacity-based transmission tariffs, i.e. those set by the Matrix RPM. Non-transmission services are defined as "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." See Section 4.2 of consultation paper for further detail on these categories and Section 3.3 of this paper for the CRU's decisions in this area.

The current methodology for gas transmission tariff setting is detailed in 2015 decision (CER/15/140). The methodology is referred to as the Matrix methodology or Matrix RPM (reference price methodology). A review of this methodology has been undertaken in fulfilment of Network Code requirements.

1.2.2 Development of the current methodology

The Matrix RPM was developed following a tariff reform process begun by CRU in 2011. As part of that process the CRU initially examined the principles of reform, which were published in CER/12/087. CER/12/087 set out a number of conclusions, which have led to the development and implementation of the current Matrix RPM. The conclusions were based on the fact that without reform, a lower utilisation of the interconnectors driven by the availability of other supply sources would have a significantly negative effect on consumers by increasing the cost of the marginal source of gas in Ireland. That would have put upward pressure on the price of Irish wholesale gas. In addition, any new entry onto the system would further exacerbate the marginal price, thereby leading to even more ineffective competition. One of the key conclusions resulting from CER/12/087 was that tariffs at each entry point to the Irish transmission system should be set on a Long Run Marginal Cost (LRMC) basis.

Following CER/12/087, the CRU set about developing the RPM that is currently in place. That process concluded in July 2015 with the publication of CER/15/140. The decisions reached in CER/15/140 were based on the reforms set out in the CRU's 2012 decisions. CER/15/140 directed GNI to develop a new RPM for the calculation of entry and exit tariffs, which allocates the recovery of the transmission services revenue of GNI, between transmission network users. The chosen methodology is known as the forward-looking Matrix methodology, or Matrix methodology/RPM for short. The principles in CER/15/057 that provided the basis for the CRU's decision drew from the principles originally established in CER/12/087. Those criteria were (1) predictability, (2) stability and (3) equity effect & promote effective competition.

It is worth noting that in the latter years of the reform process the CRU was guided by the tariff developments already taking place at an EU level, specifically the publication of the ACER Framework Guidelines on Tariffs¹² and at the end of 2014, the publication of ENTSOG's Draft Network Code on Tariffs¹³. As a result, only minimal changes to the reference price methodology (RPM) have been required in order to achieve a harmonised transmission tariff methodology for gas.

However, the aim of this decision is not only to ensure compliance with the TAR NC but also to ensure that the tariff methodology continues; to be fit for purpose, to take into account the unique

¹² [ACER Framework Guidelines on Tariffs.](#)

¹³ [ENTSOG's Draft Network Code on Tariffs.](#)

characteristics of the Irish system, and in so far as possible, to be future proofed in the case that there are significant changes to the Irish system, such as the addition of a new gas supply point (i.e. entry point) to the transmission system.

1.2.3 Review of the methodology as required by the European Gas Network Code

Regulation (EC) No 715/2009 set out the European Union (EU) wide rules for gas, which have the objectives of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks. A crucial step in reaching those objectives is the European Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (TAR NC).¹⁴

A varying approach to tariff setting for gas transmission services among EU Member States can make using EU gas transmission networks more complex for network users. It can lead to inefficient use and development of the transmission networks, and, potentially, to inefficient gas trades. The TAR NC is aimed at overcoming such issues. Specifically, the TAR NC aims at increasing the transparency of transmission tariffs and the methodologies used to set these tariffs.

Article (Art.) 26 of the TAR NC requires the CRU to review and to consult on the matrix reference price methodology¹⁵ being applied in Ireland. Art. 28 requires the CRU to review and to consult on aspects of the tariff setting methodology such as those relating to discounts, multipliers and seasonal factors. As part of those reviews, the CRU published in December 2018, a consultation (CRU/18/247) on the harmonised transmission tariff methodology for gas¹⁶.

1.2.4 CRU review process

The first step undertaken by the CRU was a gap analysis to identify any areas of potential non-compliance with our current tariff setting methodology and the TAR NC. The CRU then investigated any additional areas within the gas tariff methodology that needed to be examined or re-examined to take into account the characteristics of the Irish gas network and gas market.

In conducting this work the CRU has been guided by several criteria, which have led to the development of the decisions presented in this paper. Firstly, the criteria in CER/15/057, which drew from the principles originally established in CER/12/087 (e.g. LRMC). These criteria are (1)

¹⁴ [Commission Regulation \(EU\) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas](#)

¹⁵ The reference price methodology (RPM) is the same as the transmission tariff model. The RPM sets the reference price, or in simple terms, the tariff for annual firm capacity. For annual firm capacity the reference price is the same as the tariff. There are a number of additional capacity products which shippers can book for a shorter time period. The tariffs for these products are derived from the reference price for annual firm capacity, see Section 3.12 for further detail.

¹⁶ It should be noted that this network code does not set the rules for setting tariffs for use of the gas distribution system. The setting of tariffs for use of the gas distribution system involves a separate methodology.

predictability, (2) stability and (3) equity effect & promote effective competition. Secondly, the criteria set out in TAR NC Art. 7; which can be summarised as (a) transparency, (b) cost-reflectivity, (c) non-discrimination and cross-subsidisation, (d) volume risk, and (e) cross-border trade.¹⁷

In carrying out the review the CRU worked closely with GNI as the TSO. GNI carried out analysis of aspects of the methodology and updated the RPM (i.e. the Matrix model) to reflect the latest network topology and potential new entry points. GNI has also added new functionality to the RPM and developed a capacity weighted distance (CWD) counterfactual RPM in accordance with the TAR NC. The CRU carried out a technical review of both the matrix and CWD RPM models to ensure they were robust and that the indicative modelling results presented were accurate.

In addition, the CRU reconvened the Networks Tariff Liaison Group (NTLG). The NTLG included a wide range of gas industry stakeholders, such as GNI, indigenous natural gas field producers and explorers, potential LNG and RNG developers, Shippers, suppliers and end customers. There was also attendance from the Isle of Man (Manx Utilities) who rely on GB-Ireland Interconnector 2 (IC2) as the primary source of delivering gas. A full list of participants was detailed in Appendix B of the consultation paper (CRU/18/247). Feedback from those participants provided the basis for many of the proposals set out in the CRU's consultation paper.

The purpose of the NTLG was to provide a peer review and analysis of information to ensure that the tariff methodology was considered in the context of the Irish gas network and to ensure that the modelling inputs and parameters were scrutinised before the publication of the consultation. Prior to the publication of the consultation paper the NTLG met three times and initial modelling evidence was shared with participants. In addition, an open stakeholder forum prior to the NTLG meetings provided an introduction to the project.

The CRU published its consultation paper on 11 December 2018, commencing a two-month consultation period. Following the publication of the consultation the CRU organised a second open stakeholder forum, at which it presented its proposals and provided a platform for discussion amongst stakeholders. In addition, GNI hosted a conference call during which it provided a walkthrough of the RPM workbook and fielded any queries from stakeholders. The CRU wishes to thank the NTLG participants for their valuable contributions.

1.3 Purpose of this paper

On 11 December 2019 the CRU published its consultation paper on a proposed harmonised transmission tariff methodology for gas. The CRU also filled out ACER's consultation template,

¹⁷ Compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Art. 13 of Regulation (EC) 715/2009.

which provides information on where to locate the items set out in Art. 26 & 28.¹⁸ In the consultation paper the CRU made requests for comment on its review of the current tariff setting methodology under Art. 26 & 28 of the TAR NC. The CRU received 20 responses to the consultation and the CRU wishes to thank these stakeholders for their feedback. In accordance with the TAR NC the CRU then published a paper summarising responses to the consultation ([CRU/19/025](#)), as well as the responses themselves. Finally, ACER having reviewed the CRU's consultation and the responses, published its analyses of the CRU's consultation on 10 April 2019.¹⁸

Having received responses from stakeholders and ACER's analysis, the CRU is now publishing its decision on the items set out in Art. 26 and Art. 28 of the TAR NC. The views of stakeholders and ACER have been considered in the development of the decisions in this paper. The CRU has also responded to ACER recommendations in Appendix B of this paper. With this decision paper the CRU not only aims to ensure that a harmonised transmission tariff methodology exists in Ireland, but it also aims to ensure that the Irish transmission tariff structure continues to appropriately reflect the unique characteristics of the Irish gas network and market. Importantly, this should ensure the best outcomes for Irish gas customers.

1.4 Related Documents

Some documents related to this publication are provided below:

- ACER's analysis of the CRU consultation is available at this clickable [link](#).
- ACER's consultation template, which been filled out by the CRU and is available at this clickable [link](#).
- CRU Summary of Responses to Consultation Paper ([CRU/19/025](#)).
- CRU Consultation Paper on Harmonised Transmission Tariff Methodology for Gas ([CRU/18/247](#));
- Diversity premium calculation workbook ([CRU/18/247c](#));
- Capacity/commodity split impact assessment workbook ([CRU/18/247d](#));
- Expansion constant calculation workbook ([CRU/18/247e](#));
- Annuitisation factor calculation workbook ([CRU/18/247f](#));
- Virtual Reverse Flow probability of interruption calculation workbook ([CRU/18/247g](#));
- CRU Decision Paper on October 2017 to September 2022 Transmission Revenue for Gas Networks Ireland ([CER/17/260](#));

¹⁸

https://acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx

- CRU Decision Paper on the Entry/Exit Tariff Methodology ([CER/15/140](#));
- CRU Draft Decision Paper on the Entry/Exit Tariff Methodology ([CER/15/057](#));
- CRU Decision Paper on the Regulatory Treatment of the BGÉ Interconnectors ([CER/12/087](#));
- [Regulation \(EC\) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation \(EC\) No 1775/2005](#);
- [Commission Regulation \(EU\) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas](#); and,
- The current reference prices and GNI's simplified transmission tariff model are available at the following clickable [link](#).

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

1.5 Structure of Paper

This decision paper is structured in the following manner:

- Section 1 provides an introduction and background, the purpose of this paper, an explanation of the how the CRU arrived at a decision and a list of related documents.
- Section 2 provides a summary of the Irish transmission network and gas market and information on the supply scenarios examined.
- Section 3 details the CRU's decisions.
- Section 4 provides a summary of the CRU's decisions.
- Appendix A provides the reference prices for gas year 19/20.
- Appendix B provides the CRU's response to ACER's recommendations.
- Appendix C provides a breakdown of the multiplier and seasonal factor multipliers into their individual parts.

2 Irish Transmission System and Gas Market

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 and the gas market. This includes the network topology, Irish gas supply and demand, and the design of the current entry-exit system. In addition, this section highlights some potential changes to the transmission network.

2.2 Irish transmission network topology and gas supply

The natural gas transmission network is 2,427km in length, consisting of high-pressure steel transmission pipelines. There are both onshore (2,015km) and offshore (412km) pipelines. See Figure 1 for a map of the ROI transmission system. The offshore pipeline length is made up of portions of the two gas interconnectors (IC1 and IC2) that connect Ireland to Brighthouse, Scotland. There is a sub-sea offtake point from IC2 that supplies the Isle of Man.

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 Corrib gas field enters the Irish transmission system. The addition of the Corrib entry point at the end of 2015, brings the total number of entry points on the system to three including the Moffat interconnection point (IP) in Scotland, and the Inch entry point, which is the entry point for gas from the Kinsale gas fields. In addition, to the Moffat IP there is also an IP with the Northern Irish (NI) gas transmission system at Gormanston. However, no commercial gas currently flows to NI from the Republic of Ireland (ROI) system, it is used for emergency support only. In the event that commercial flows to NI did occur the Gormanston IP could also become an entry point for virtual reverse flow¹⁹ (VRF) from the NI system to the ROI system.

With regard to flows of gas from GB to NI, there is a Transportation Agreement (TA) in place

¹⁹ See section 2.3 for further detail on virtual reverse flow.

between GNI(UK)²⁰ and Premier Transmission Limited (PTL)²¹. This agreement is supported by an intergovernmental treaty²². The TA enables use of part of the IC1 onshore pipeline in Scotland, between Moffat, and the point of connection on land in Scotland of the connecting pipe to NI (i.e. Twynholm), to facilitate flows from GB to NI customers. Further information on this arrangement is available in Section 3.2.3.3.

The majority of gas demand in Ireland is currently supplied by the Corrib gas field, which supplied 60% of system throughput in the calendar year 2017. The Kinsale gas fields provided an additional 7%, with imports via the Moffat entry point in Scotland providing the remaining 33%. Ireland's dependence on imports from Great Britain (GB) is increasing once again as production declines at the Corrib gas field, and this trend will continue unless new sources of indigenous supply are brought on stream. Potential new sources of supply are discussed further in Section 2.4.

109 exit points from the transmission system are included in GNI's latest model. Most of these are points of entry to the distribution system, however these exit points also include the Gormanston IP, the Moffat IP exit (VRF only) and connections to large gas consumers such as power generators.

²⁰ GNI(UK) is the owner of the high-pressure gas interconnectors between Moffat in Scotland to the end of UK Territorial Waters (onshore Scotland Infrastructure). This infrastructure is operated by GNI. GNI(UK) is a wholly owned subsidiary of Gas Networks Ireland (GNI), which sits within the Ervia Group.

²¹ Premier Transmission Limited owns and operates the natural gas transmission pipeline from Scotland to Northern Ireland (SNIP).

²² Irish Treaty Series 1993 No.1.

Figure 1: Gas Networks Ireland's transmission system



2.3 ROI Gas Market

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, as GB gas is the marginal source of gas supply to Ireland. The National Balancing Point, commonly referred to as the NBP, is the virtual trading location for GB natural gas. Therefore, the cost of gas at the NBP plus the cost of transportation to Ireland strongly influences the price at the Irish Balancing Point (IBP), i.e. the cost of wholesale gas in Ireland.

Since 2017 an electronic gas trading spot-market has been in place in Ireland.²³ This allows buyers and sellers to trade gas at the IBP via a trading platform. A trading platform promotes liquidity at the

²³ <https://www.ebi.ie/>

IBP, thereby increasing gas price transparency and reducing the cost to Shippers of matching supply and demand in Ireland. Increased liquidity and the development of a wholesale price for natural gas at the IBP should ultimately benefit Irish gas consumers by reducing costs.

Although there are no physical cross-border exit points currently used for the commercial flow of gas, there is a Virtual Reverse Flow (VRF) service in use at Moffat.²⁴ VRF is a 'reverse flow' service offered on a virtual interruptible basis, at the IP, to enable Shippers to virtually flow gas from ROI to GB.²⁵

The interaction between the sources of gas to Ireland and the tariff methodology continues to be essential when considering the tariff methodology in Ireland. As such it is important that the CRU assess the tariff methodology against potential future changes to the sources of gas to Ireland to ensure that the methodology is robust, that the principles and rationale set out in CER/12/087 continue to be met and that it complies with the TAR NC.

2.4 Potential future supply scenarios

In compliance with Art. 26 of the TAR NC the CRU is required to provide a description of the RPM and a comparison of the indicative reference prices as calculated by the RPM and the indicative reference prices calculated using the capacity-weighted distance (CWD) counterfactual. In the consultation paper the CRU provided this comparison in Section 3.3.

In order to provide a robust comparison, the CRU, with input from stakeholders, developed three potential gas supply scenarios to ensure that the RPM is robust to changes in sources of supply. When forming these scenarios, the CRU has focused on potential supply scenarios within the next five years. The CRU is of the view that this period is suitable as the CRU will be required to carry out a consultation in accordance with Art. 26 at least every five years. The CRU presented three scenarios in the consultation paper. These scenarios are by no means exhaustive, they help to provide an estimation of the effect on indicative reference prices and the stability of these reference prices, given potential significant changes to gas supply in Ireland. The scenarios are included in the table below, for further information on these scenarios see Section 2.4 of the consultation paper.

²⁴ A VRF service is also in place at Gormanston, but as there are currently no commercial flows via this IP there is no practical way for a shipper to use VRF.

²⁵ 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.

Table 1: Potential future gas supply scenarios examined in this consultation

| Entry Point | Current | Scenario 1 | | Scenario 2 | | Scenario 3 | |
|-------------|---------|------------|-------|------------|-------|------------|-------|
| | 18/19 | 19/20 | 23/24 | 19/20 | 23/24 | 19/20 | 23/24 |
| Moffat | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Bellanaboy | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| RNG | ● | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| Inch | ✓ | ✓ | ● | ✓ | ● | ✓ | ● |
| Foynes | ● | ● | ● | ● | ✓ | ● | ● |
| Innisfree | ● | ● | ● | ● | ● | ● | ✓ |

In addition to modelling potential changes to the network topology, it is also necessary to make an estimate of future gas demand in ROI and how this demand will be met by each supply/entry point. These forecasts have been developed by GNI and are an important step as the level of demand and supply has a significant effect on the level of tariffs. This supply and demand information is used to calculate the forecasted contracted capacity at entry points and exit points on an annualised basis²⁶. The total forecasted contracted capacity and forecasted commodity at entry was assumed to be the same across each scenario. The table below, which was presented in the consultation paper, details the potential supply scenarios that have been modelled and the annualised forecasted contracted capacity assumed for each scenario. The key point to take away from the scenarios is the effective reduction that the new sources of supply have on the projected bookings at Moffat.

For further information on how GNI forecasts demands, see Section 2.4 of the consultation paper.

²⁶ As capacity can be booked for different time lengths (i.e. annual, monthly, daily) it needs to be converted into a single annualised number so that it can be inputted into the RPM.

Table 2: Scenarios and annualised forecasted contracted capacity (GWh/d)

| | Projected 18/19 Bookings | Scenario 1 | | Scenario 2 | | Scenario 3 | |
|---------------|--------------------------|------------|-------|------------|-------|------------|-------|
| | | 19/20 | 23/24 | 19/20 | 23/24 | 19/20 | 23/24 |
| Moffat | 128 | 155 | 206 | 155 | 22 | 155 | 100 |
| Bellanaboy | 82 | 72 | 43 | 72 | 43 | 72 | 43 |
| RNG | n/a | 0 | 12 | 0 | 12 | 0 | 12 |
| Inch | 6 | 4 | 0 | 4 | 0 | 4 | 0 |
| Foynes LNG | n/a | n/a | n/a | 0 | 184 | n/a | n/a |
| Innisfree LNG | n/a | n/a | n/a | n/a | n/a | 0 | 106 |
| Exits | 280 | 289 | 313 | 289 | 313 | 289 | 313 |

3 CRU Decisions

3.1 Introduction

On 11 December 2019 the CRU published a consultation paper on a proposed harmonised transmission tariff methodology for gas. In the consultation paper the CRU made requests for comment on a number of aspects of the proposed methodology. The CRU received 20 responses to the consultation and the CRU wishes to thank those responders for their feedback. On 13 April the CRU published these responses as well as a summary of them (CRU/19/025). The responses were also made available to ACER. Having reviewed the CRU's consultation paper and the responses received, ACER published its analyses of the CRU's consultation on 10 April 2019.

Having considered in full all responses of stakeholders and ACER the CRU is now publishing its decision. The CRU's decisions are set out in the following sections. Each section provides the CRU's decisions and the rationale for them but also a summary of the consultation proposal, a summary of the responses received and the CRU's response to comments.²⁷

The decisions set out in this paper will apply for the calculation of transmission capacity tariffs for the gas year 2019/20 unless otherwise stated.

3.2 Reference price methodology

3.2.1 Introduction

The reference price methodology (RPM) is defined in Art. 3(2) of the TAR NC as “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”. In simple terms, the RPM is the methodology approved by the CRU to calculate the annual tariffs at entry and exit, which allow GNI to recover their transmission services revenue. Art. 7 of the TAR NC sets out the requirements that the RPM must meet, however, TAR NC does not explicitly state the type of RPM that should be used.

3.2.2 Consultation proposal and comments

In the consultation paper the CRU stated that it is of the view that the Matrix RPM²⁸ continues to be suited to the characteristics of the Irish gas market and that it continues to comply with the CRU's own principles of tariff reform and with the principles and requirements of the TAR NC. The CRU provided detailed reasoning for this view in Section 3.4 of the consultation paper. The CRU

²⁷ The full responses can be viewed in CRU/19/025.

²⁸ See Section 3.2.1 of the consultation paper for a detailed description of the Matrix RPM.

proposed to continue to apply the Matrix RPM and requested comment from stakeholders.

CRU consultation request for comment

3A. What are your views on the CRU's proposal to continue to apply the Matrix RPM?

A clear majority of respondents agreed with the CRU's proposal to continue to apply the Matrix reference price methodology (Matrix RPM).

Some of the respondents noted the stability and certainty offered by the Matrix RPM and considered that it is well-suited to the Irish gas market. Some respondents expressed the view that the Matrix RPM is well aligned with the principles of the TAR NC and produces stable tariff differentials which provide clear investment signals. Respondents also noted that a rigorous consultation process was held before the Matrix RPM was first implemented by CER/15/140.

One respondent (Shannon LNG) did not support the Matrix RPM. This respondent contended that it could lead to cross-subsidisation and noted a large disparity between the Moffat-Foynes differential under the Matrix RPM and the CWD RPM as evidence for this. That respondent was also of the view that it was more appropriate to use a multiplicative, rather than additive, rescaling factor, and that the additive rescaling may cause undue cross-subsidisation.

One respondent (Mutual Energy) considered that the differences between the Matrix RPM and the CWD approach were not adequately described by the CRU, and that the Matrix RPM fails to meet the criteria set out in Art. 7 of the TAR NC. That respondent took issue with the transparency of the Matrix RPM description and how the results had been presented.

In addition, there were a number of comments regarding the methodology in the context of Northern Ireland. Three respondents (Mutual Energy, Firmus Energy and Phoenix Natural Gas Limited (PNGL)) expressed concern at the possible effects of the CRU's proposed methodology on Shippers and customers in Northern Ireland. Those respondents sought clarification on the inclusion of Twynholm in the Matrix RPM and whether the tariff would apply to NI Shippers.

Some respondents (Mutual Energy and PNGL) were of the view that the indicative reference prices for Twynholm and Gormanston tariffs were too high and noted that the tariffs were lower under the CWD approach. One respondent (Mutual Energy) stated that they presumed that the calculated tariffs at those points would apply to Shippers who wish to transport gas outside of the Transportation Agreement²⁹ arrangements. In addition, the respondent noted that arrangements were also in place for gas to flow from Moffat and the GNI (UK) system to the Isle of Man but that no separate tariff had been calculated for that route.

²⁹ Commercial arrangements for the SNIP's interface with the GNI system are set out in this agreement.

Two respondents (Mutual Energy and PNLG) state that the proposed tariffs for Twynholm and Gormanston make transit flows uncompetitive, distorting cross-border trade. They further noted that these points can receive gas from the UK/Moffat entry point only. One respondent (Mutual Energy) stated that the tariffs result in undue cross subsidisation and equated to NI Shippers making a double contribution to the cost of the interconnectors, which was found to be legally unsound in 2014. The respondent stated that the CRU has given little attention to potential transit flows and that the consultation was not compliant with the cost allocation assessment (CAA) requirement.

3.2.3 Response to comments

3.2.3.1 Matrix RPM compliance - general

The CRU notes that the vast majority of respondents agreed with the CRU's proposal to continue to apply the Matrix RPM. With regard to the more general comments on compliance the CRU notes that in Section 3.4.2 of the consultation paper the CRU provided detailed reasoning as to why it is of the view that the Matrix RPM is compliant with the criteria in Art. 7 of the TAR NC. The CRU has considered the detailed responses from respondents regarding compliance below. The CRU continues to be of the view that the Matrix RPM is compliant with the criteria in Art. 7 of the TAR NC for the reasoning set out in Section 3.4.2 of the consultation paper. In terms of ACER's analysis³⁰, and the arrangements at Twynholm, the CRU is providing additional information regarding these arrangements to ensure that they are clear – see section 3.2.3.3

3.2.3.2 Matrix RPM compliance – cross subsidisation

In terms of cross-subsidisation, a respondent pointed to the difference between the Moffat-Foynes differential under the Matrix RPM and the CWD RPM. In the view of the CRU this is not evidence of cross-subsidisation but rather a result of the different cost signals that the Matrix RPM (forward-looking) and CWD RPM (backward looking) send.³¹ As stated in the consultation cross-subsidisation is a result of tariffs that are not cost-reflective, with the deviation from cost-reflectivity resulting in a user of the entry-exit system being allocated a tariff that does not reflect the differences in costs of different points on the system. However, as complete cost-reflectivity is impossible to achieve there will always be some level of cross-subsidisation. The test for cross-subsidisation is to ensure that there is no *undue* cross-subsidisation. Given that the CRU has chosen a RPM that is based on providing forward-looking signals that are cost-reflective and has applied the same cost drivers to derive tariffs at all entry/exit points, the CRU is of the view that

³⁰ In particular, paragraphs 66, 71, 75, 79 and 85.

³¹ In the consultation paper the CRU noted that “the CRU continues to be of the view that the benefit of a forward-looking cost concept is that it ensures reference prices are cost-reflective, by ensuring that entry is incentivised in the case where an entry point can beat the Moffat cost of expansion. In addition, ACER has stated that incremental costs may be appropriate in expanding systems, either resulting from an increase in demand, or triggered by a change in the general system sourcing”.

there is no *undue* cross-subsidisation present under the Matrix RPM. In addition, ACER noted that it seems that instances of intra-system users' cross-subsidisation are not undue.

One respondent is also of the view that undue cross-subsidisation may be present as it is more appropriate to use a multiplicative, rather than additive, rescaling factor.

As stated the CRU's decision to apply the Matrix RPM is based on the assessment of the RPM against a number of criteria (see Section 1.2.4). However, in general, tariff setting is generally based on two principles.

- A. Cost-reflectivity: Customers connected to the system should incur the costs they impose on the network and take these into account when making private investment and operational decisions. This means that also socially optimal decisions are made by the customer when responding to tariffs. Decision making by the customer relates to future costs, as these costs can still be influenced, whereas historical costs are sunk. The incremental costs created by connecting customers are the long-run marginal costs of the networks, and tariffs are cost reflective when long-run marginal costs are reflected in the tariffs.
- B. Cost-recovery: The TSO should be able to recover the incurred costs from its customers. Cost recovery relates to all costs, including those costs already incurred, i.e. sunk costs. Economic theory provides limited guidance on the recovery of sunk costs, other than that this should be done in the least-distortive way, i.e. the impact on future decisions should be minimised. Equity is a second concept often used to ensure the outcome of cost recovery is fair.

The Matrix RPM adheres to both of these elements as the CRU aims for efficient expansion of the system and the recovery of sunk costs. The Matrix RPM is a forward-looking methodology that calculates the cost of additional incremental capacity at points on the network.

The Matrix RPM is cost-reflective with respect to the absolute difference in tariffs (differentials). These differentials represent the differences in marginal costs of expanding the system at different locations. These differentials are created by the first part of the tariff, the primary tariff.³² If an entry point is close to load, the marginal costs (driven by distance) will be small, whereas an entry point further away will incur greater costs. A customer connecting to the system can make a socially optimal decision if the two tariffs reflect this difference (it might incur different private costs at each of the locations as well).

Although the Matrix RPM attempts to capture the specific costs of each path to as complete a

³² To do this, unit costs are calculated for each entry-exit path based on the expansion constant (cost of building a pipeline (capacity) including compression) and annuitisation factor (annual revenues that would be required to finance such an asset) and the distance between each entry point and exit point. The Matrix RPM uses a mathematical formula (i.e. least squares) to set a primary (or raw) tariff for each entry and exit point. This results in differences in the primary tariffs from one point to the next.

degree as possible, it will not directly recover all of the TSO's transmission services revenue. Therefore, in order to recover the TSO's transmission services revenue an adder is used in accordance with the Art. 6.4(c).

Additive rescaling does not distort the cost-reflectivity of the Matrix RPM as it simply adds the same amount to each primary tariff. This maintains the differentials created as part of the primary tariffs. In other words, the €/GWh/d/km difference in the primary tariffs between entry points remains unchanged. This would not be the case if multiplicative rescaling was applied, as this €/GWh/d/km difference would be subject to a multiplier, leading to either a decrease or increase in the difference. This would weaken the tariff signals and therefore the underlying costs of the network to the customer, who can rationally optimise the social and private benefits, leading to socially optimal network expansion.

In the context of the Irish system, the CRU notes that multiplicative rescaling gives rise to a substantial increase in the tariff at Moffat.³³ Multiplicative scaling is therefore not only inconsistent with the economic rationale of the Matrix approach, but it also has a significant impact on the costs to final customers, equity and the stability of tariffs. In addition, multiplicative rescaling amplifies the effect of changes to the Irish network. Instead, an additive approach generates a stable and cost-reflective differential between entry points and the marginal entry point at Moffat, allowing for long-term investments to take place.

As a result of the above the CRU is of the view that the additive approach is appropriate.

3.2.3.3 Matrix RPM compliance – Transparency & Northern Ireland arrangements

The CRU notes the comment suggesting that the differences between the Matrix RPM and the CWD approach were not adequately described and that the Matrix RPM description was not transparent. In Section 3.2 of the consultation paper the CRU provided a description of the Matrix RPM and the counterfactual CWD RPM. The CRU would be happy to discuss the workings of specific aspects of the methodology directly with any party. However, the CRU considers that in general sufficient information had been provided on the methodology and notes ACER opinion that “*CRU explains the Matrix RPM, which is a complex one, and guides the users to understand and reproduce the reference prices and their forecasts*”.

As highlighted by some respondents there was a lack of information in the consultation paper regarding the current arrangements at the Twynholm exit point. This was also noted by ACER in their analysis of the CRU's consultation document. Recognising this, the CRU has provided below additional information on the Twynholm arrangements.

³³ An assessment of the effect of additive and multiplicative rescaling was examined at the third NTLG, which can be found on slide number 21 of the NTLG 3 slides (CRU/18/247b).

Twynholm arrangements

A Transportation Agreement (TA) is in place between GNI(UK)³⁴ and Premier Transmission Limited (PTL)³⁵ for all flows from Great Britain to Northern Ireland customers. This agreement is supported by an intergovernmental treaty³⁶.

In parallel to the construction of the IC1 pipeline in the early 1990's, which was constructed to transport natural gas from GB to ROI, the equivalent parties in Northern Ireland were deliberating the construction of a separate pipeline that would transport natural gas directly from Great Britain to North Ireland. Parties from both jurisdictions entered into discussions to explore how to avoid any unnecessary duplication of infrastructure. This would lead to a more efficient use of the planned infrastructure and a better outcome for customers in NI and ROI. Use of part of the IC1 onshore pipeline in Scotland to facilitate flows from GB to NI customers was agreed upon. This agreement was enshrined in an intergovernmental treaty. Article 10 of the treaty ensures that the competent authorities in NI shall, have on fair commercial terms (relating where appropriate to the installation of compression), a portion of the capacity of the part of the pipeline between Moffat, and the point of connection on land in Scotland of the connecting pipe to NI (i.e. Twynholm). The capacity available is up to 8.08mscm.

The details of the specific commercial arrangements are laid out in the Transportation Agreement (TA) between GNI(UK) and PTL. Parties transporting gas in accordance with the TA are not subject to the Moffat entry tariff or a Twynholm exit tariff.

Application of tariffs at Gormanston and Twynholm

A primary focus of the Third Package suite of Gas Network Codes is to harmonise the rules that apply to access gas transmission systems across Europe. The scope of the TAR NC differs from other network codes in that it applies to all entry & exit points into and out of the transmission system whereas other network codes do not. TAR NC Art. 6.3. "*The same reference price methodology shall be applied to all entry and exit points in a given entry-exit system*".

At the time of the consultation, the CRU treated Twynholm as an exit point under the TAR NC. As such, an exit tariff for Twynholm was included in GNI's tariff model: as is required for all exit points under Art. 6.3 of the TAR NC. For clarity, in publishing that tariff, the CRU was not of the view that parties transporting gas in accordance with the TA would be subject to a Twynholm exit tariff.

Although a tariff for Twynholm was included in the consultation, the CRU notes that the Code of

³⁴ GNI(UK) is the owner of the high-pressure gas interconnectors between Moffat in Scotland to the end of UK Territorial Waters (onshore Scotland Infrastructure). This infrastructure is operated by GNI. GNI(UK) is a wholly owned subsidiary of Gas Networks Ireland (GNI), which sits within the Ervia Group.

³⁵ Premier Transmission Limited owns and operates the natural gas transmission pipeline from Scotland to Northern Ireland (SNIP).

³⁶ Irish Treaty Series 1993 No.1.

Operations does not facilitate the booking of capacity by RoI shippers at Twynholm. Given this inability to book capacity, the CRU considers that, for the purposes of the TAR NC, Twynholm is not an exit point. As such, the CRU has removed the Twynholm point from the tariff model and a tariff is not calculated for Twynholm. This change leads to a minimal <0.5% increase in the Moffat entry point tariff and a reduction in the tariffs at all other entry points. There is no effect on the exit tariffs.

With regard to Gormanston, it is an Interconnection Point (IP). A tariff for this IP was included in the consultation in accordance with TAR NC Art. 6.3. To date no party has been charged the Gormanston exit tariff.

For clarity, currently no Shippers pay an exit tariff at Twynholm due to the TA and no Shippers pay an exit tariff at Gormanston IP due to the fact there are currently no commercial flows. A tariff is not derived for the Twynholm point as it is not an exit point from the ROI system. However, Gormanston is an IP as defined under EU rules and as such an exit tariff is calculated at this point in accordance with Art. 6.3 of the TAR NC. In the absence of alternative arrangements, any Shipper who chooses to exit gas at the Gormanston IP would be subject to the applicable tariff, just as any Shipper on the ROI system who exits gas at an exit point is subject to the applicable exit tariff.

The level of the tariffs at Gormanston and Twynholm

Notwithstanding the above decision to no longer calculate a tariff for Twynholm the CRU has responded to comments asserting that the level of tariffs at Gormanston and Twynholm appear high and may distort cross border flows or be an indication of cross-subsidisation.

It is again important to state that the Matrix RPM is applied consistently to all exit and entry points. The rationale behind a consistent application of the RPM is to ensure that tariffs for customers at one point do not unduly discriminate against tariffs for customers at another point. The same cost drivers are applied in order to derive the tariffs for all entry/exit points and therefore both non-domestic and domestic exit points.

After the introduction of the concept of the entry-exit system by Regulation (EC) No 715/2009, transmission costs are no longer directly associated to one specific route as entry and exit capacity can be contracted separately, and network users can have gas transported from any entry to any exit point (not necessarily the same physical molecules). It is this single system approach that the CRU applies to derive tariffs for use of the ROI system. In a single system approach, e.g. the Matrix approach in Ireland or the Virtual Hub approach in GB, the gas Shipper is essentially paying an entry tariff to get to a hub such as the IBP or NBP (where gas can then be traded) then an exit tariff is paid to get the gas to the customer. The tariffs paid at the entry and exit points do not reflect the specific costs of the route, but rather the tariff reflects the cost drivers of the entire network not just those costs associated with a specific route.

As the CRU is applying a single system approach and the cost drivers of the Matrix RPM consistently, regardless of user type (intra-system or cross-system), the CRU is of the view that no issues of discrimination or undue-cross subsidisation are present.

The CRU notes respondents comments that the CWD model provides lower tariffs for Gormanston and Twynholm. In terms of Twynholm, the CRU notes that Twynholm is not to be treated as an exit point for the purposes of the TAR NC (see section 3.2.3.3 for more details). As such, it will not be included in the tariff model and no tariff will be published for Twynholm.

In relation to Gormanston, the CRU would note that the CWD RPM can lead to significantly higher costs for this exit point relative to the Matrix RPM. This was illustrated in the scenario modelling provided in the consultation paper. The below table is taken from the consultation paper and summarises the outcomes of that modelling. It shows that the exit tariffs for Gormanston remain relatively stable under the Matrix RPM across all scenarios. This is not the case for when the CWD RPM is applied. In addition, it can be seen that although under scenario 1, the Matrix RPM calculates significantly higher tariffs than the CWD RPM, in scenario 2 the opposite is true.

Table 3: Comparison of exit tariffs calculated by Matrix and CWD RPMs (€/MWh).

| | Scenario 1 | | Scenario 2 | | Scenario 3 | |
|------------------------|------------|-----|------------|-----|------------|-----|
| | Matrix | CWD | Matrix | CWD | Matrix | CWD |
| Equalized exits | 430 | 430 | 430 | 430 | 430 | 430 |
| Gormanston | 408 | 290 | 423 | 526 | 425 | 416 |

Note: Entry/exit split of 33:67 applied in both RPMs and the year analysed is 2021/22.

Finally, with regard to the assertion by one respondent (Mutual Energy) that the approach being applied was found to be legally unsound in 2014, the CRU notes that the referred to legal advice (CER/14/773a) was based on a tariff methodology that is no longer in place, and one which was not a single system approach but rather one whereby tariffs were derived to remunerate costs of specific network assets (e.g. Inch tariff, Onshore tariff, Interconnector tariff). Alongside the publication of this advice in October 2014, the CRU published a Notification to Industry (CER/14/773) on the prevailing tariff for Gormanston exit. In that notification the CRU stated that the exit tariff would be calculated in accordance with the methodology chosen as part of the tariff reform process [that process was concluded in 2015 and the Matrix RPM was chosen]. As a result, the CRU has calculated a Gormanston exit tariff using the Matrix RPM since gas year 2015/16.

Cost allocation assessment

Finally, the CRU notes the comment that it had not given sufficient consideration of potential transit flows and that the consultation is not compliant with the cost allocation assessment (CAA) requirement. The CAA referred to in that response aims to evaluate whether any cross subsidisation occurs between intra-system and cross-system network use. Consistent with the TAR NC requirements the CRU undertook a cost allocation assessment (see Appendix A of the consultation paper), as detailed in Art 5. However, as there were no transit flows via the ROI

transmission network the test provided limited additional information in the Irish context to support the assessment of this criteria, returning a result of n/a. The CRU had not assessed cross-system flows as there were no cross-system flows forecasted by GNI. To be clear, the CRU does not consider gas flowing from GB to NI via the Scottish Infrastructure as cross-system flows, and to incorporate those flows into a CAA would be inappropriate given the presence of an intergovernmental treaty and TA, which allows for the transportation of this gas on fair and commercial terms. However, the CRU will continue to engage with the NI NRA (Utility Regulator) on the likelihood of cross-system use, and where necessary, update the CAA.

3.2.4 Decision

The CRU notes that the majority of respondents agreed with the CRU's proposal to continue to apply the Matrix RPM. The CRU also notes ACER's analysis, which confirmed the overall compliance of the Matrix RPM with the principle of cost-reflectivity. ACER noted that the proposed matrix RPM resulted in cost-based investment signals that incentivise new efficient entry into the Irish gas market. The CRU continues to be of the view that the Matrix RPM is suited to the characteristics of the Irish gas market and that it continues to comply with the CRU's own principles of tariff reform (i.e. predictability, stability and equity effect & promote effective competition) and the criteria set out in Art. 7 of the TAR NC (i.e. transparency, cost-reflectivity, non-discrimination and no undue cross-subsidisation, volume risk, and cross-border trade).

Given the above, the CRU has decided to continue to apply the Matrix RPM.

CRU Decision

1. The CRU has decided to continue to apply the Matrix RPM for the calculation of transmission tariffs.

3.3 Transmission & non-transmission services

3.3.1 Introduction

The regulated services offered by GNI can be split into two categories: transmission services and non-transmission services. The TAR NC defines the allowed revenue as "...the sum of transmission services revenue and non-transmission services revenue...". The transmission services revenue is inputted to the RPM and recovered through the subsequent transmission tariffs, while the non-transmission revenue is recovered through separate non-transmission tariffs.³⁷ The Corrib Linkline is a non-transmission service and Section 4.3.1 of the consultation paper

³⁷ Further details on allowed revenue and its recovery can be found in section 4.2 of the consultation paper.

details how this tariff is calculated. Art. 4(4) of the TAR NC highlights the set of requirements for the tariffs applicable to non-transmission services.

Art. 4(1) of the TAR NC sets out the criteria for distinguishing between transmission and non-transmission services. The defining characteristics of a transmission service are: (a) the costs of such service are caused by the cost drivers of both capacity and distance, and, (b) the costs of such service are related to the investment in and operation of infrastructure that is part of the regulated asset base for the provision of transmission services. Where one or neither of the conditions are met, the CRU may define the activity as a transmission or non-transmission service based on its own assessment subject to consultation.

3.3.2 Consultation proposal and comments

In the consultation paper the CRU chose to classify the Corrib Linkline as a non-transmission service as it is not part of GNI's regulated asset base. It was proposed that all other services (within the scope of the TAR NC)³⁸ would be classified as transmission services.

None of the consultation responses raised an issue with this choice.³⁹ In addition, ACER assessed the approach and noted that it is satisfied the requirements of Art. 4(4).⁴⁰

3.3.3 Decision

The CRU notes that no respondent raised an issue with the proposed approach to continue to treat the Corrib Linkline as a non-transmission service and continuing to apply the tariffing methodology as set out in CER/15/141. In addition, the CRU notes that ACER, in their analysis, considered that the proposed non-transmission charges satisfied the requirements of Art. 4.4 of the TAR NC. The CRU continues to be of the view that the Corrib Linkline should be classified as a non-transmission service as it is not part of GNI's regulated asset base, and that the methodology, set out in CER/15/141 for setting the tariff for the Corrib Linkline is appropriate and compliant with the TAR NC.

Given the above, the CRU has decided to continue to classify the Corrib Linkline as a non-transmission service and to continue to calculate the charge for use of the Corrib Linkline in accordance with CER/15/141.

³⁸ See Section 4.3.2 of the consultation paper for information on charges that are outside of the scope of the TAR NC.

³⁹ Some respondents noted that some other elements of the tariff methodology should be classified as non-transmission services, these responses are discussed further in the relevant sections (i.e. shrinkage and VRF).

⁴⁰ On the condition that the CRU explain how the non-transmission over- and under-recovery are addressed. This information is provided in Section B.4.

CRU Decision

2. The CRU has decided to continue to classify the Corrib Linkline as a non-transmission service and to continue to calculate the charge for use of the Corrib Linkline in accordance with the methodology set out in CER/15/141.

3.4 Shrinkage

3.4.1 Introduction

Shrinkage gas means own use gas (OUG) and natural gas required to replace unaccounted for gas (UAG). OUG means natural gas which is used by GNI for the operation of the gas transportation network or any localised part thereof, including at compressor stations and/or for pre-heating and venting purposes. UAG means natural gas which is lost or otherwise unaccounted for from the gas transportation network or any localised part thereof. GNI incurs costs to source the shrinkage gas that is used or lost in the operation of the network

To date costs associated with shrinkage on the transmission system had not been included in the transmission services revenue. GNI recovers these costs pro rata through a separate flow-based charge from gas Shippers on a monthly basis based on their throughput. Shrinkage makes up a significant portion of the costs incurred by GNI as the TSO, approximately €9.7m in 2017/18.

3.4.2 Consultation proposal and comments

In the consultation paper, the CRU proposed that shrinkage costs were to be included in the allowed revenue and classified as a transmission service. The CRU came to this view as all network users derive a benefit of the pressures being maintained throughout the system and operated to meet gas flow instructions irrespective of location on the network.

In addition, the CRU proposed that shrinkage costs should be recovered through the commodity element of the capacity/commodity split given that shrinkage costs are the main cost incurred by the TSO relating to the quantity of gas flowed.⁴¹

In Section 4.4.2 of the consultation the CRU also noted some additional factors it had considered relevant to the proposal such as volatility of tariffs, greater transparency, a potential shrinkage incentive, and the impact on the effective capacity/commodity split.

⁴¹ The recovery of shrinkage costs under the transmission service tariff arrangements presents an important element of the justification for a 90/10 capacity/commodity split. While shrinkage costs are not explicitly recovered through the commodity charge, given that the commodity charge is expected to cover costs associated with the flow of gas, such as shrinkage costs, the CRU refers to these costs as being included within the commodity charge.

Finally, the CRU proposed to implement this change beginning gas year 2019/20 and requested comment from stakeholders.

CRU consultation request for comment

4A. What are your views on the CRU's proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

There was a mixed response from respondents who commented on the proposal to include shrinkage in the allowed revenue and to class it as a transmission service with costs to be recovered through tariffs.

Amongst those in favour, respondents noted that all network users benefit from the maintenance of system pressures and access to wholesale markets that shrinkage provides. Two respondents (Manx Utilities and Aughinish Alumina) were of the view that the proposal would provide greater transparency in relation to shrinkage costs. Several respondents also considered that the proposal would make the 90:10 capacity/commodity split more cost-reflective and one respondent (Shell) considered that the proposal would ensure a level playing field for gas entering the Irish system from different supply points. One respondent (GNI) agreed that the inclusion of the shrinkage cost within the overall allowed revenue would be in line with the concept of a single gas system where all users who have access to, and use of the system, contribute to the operation and integrity of the system. Some respondents also supported the proposal stating that a uniform commodity charge should be applied to all entry points on the system; to maintain consistency in approach and to avoid undue discrimination and promote effective competition (BGE); and also, as the benefits of system usage including access to wholesale markets accrue to all networks users (ESB GT).

A respondent (VEPIL) questioned the TAR NC compliance of the proposal, stating that the cost-drivers for UAG are not technical distance capacity of the network; furthermore, the drivers for UAG are more gas network leakage and metering issues. This respondent (VEPIL⁴²) considered that the recovery of the un-accounted for gas (UAG) component of shrinkage is appropriate. However, with regard to OUG, VEPIL stated that while capacity determines the envelope of OUG use, it does not determine the quantity of OUG consumed on a day. They are of the view that it is instead decided by gas demand drivers (e.g. wind generation, ambient temperature, coal switching price etc.) and

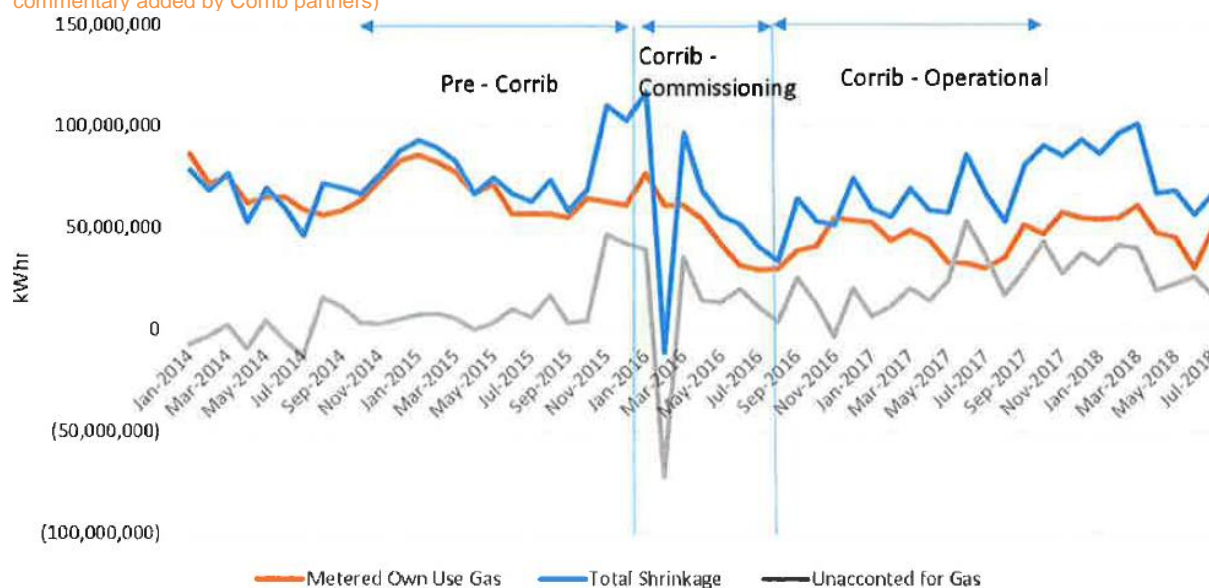
⁴² Vermilion Energy Production Ireland Ltd (VEPIL) is the operator of the Corrib gas field and responded to the questions on shrinkage and the capacity/commodity split on behalf of the Corrib partners (i.e. Equinor, Nephin Energy and Vermilion Energy Ireland Ltd (VEIL)), who also responded to this consultation. When comments are attributed to "VEPIL" in this paper, they are also attributed to the Corrib partners.

the configuration of deliveries at each Irish entry point.

From this respondent's perspective, it would be more appropriate for OUG to be to a non-transmission charge levied on those entry points where the OUG is required (to get gas to the IBP on the island of Ireland at the appropriate pressure). They suggested that such an approach would be a cost-reflective and non-discriminatory one and that this would be similar to the St. Fergus Compression fee in GB.

The respondent included the following graph in their response that details the UAG and OUG consumption from Jan'14 to Jun'18.

Figure 2: Total Shrinkage Consumption (Pg 39 GNI Code Modification Slides - 26 September 2018 – Blue lines and Corrib commentary added by Corrib partners)



The respondent stated that the above graph highlights a step reduction in OUG consumption post-Corrib commissioning when compared to OUG consumption pre-Corrib commissioning (Corrib commissioning was a gradual process increasing flowrates from the field hence the gradual reduction in OUG during the Corrib commissioning phase). The respondent argued that this illustrated previous arguments made by NTLG participants that new entry points that deliver gas into the Irish network at the ring main pressure of 70barg reduce the flow of gas at Moffat and the associated OUG. One respondent (Shannon LNG) made a similar point stating that they understand that shrinkage costs consist mostly of the cost of [operating] compressors in Scotland, and accordingly they believe that these costs should be charged to the users of the Moffat entry point.

Another respondent (Tynagh Energy) argued against the proposal to class shrinkage as a transmission service on the basis that greater flow-based charges are preferable in general to avoid placing a disproportionate weight on power generators.

Several respondents had concerns about the transparency of the proposal to class shrinkage as a transmission service. One respondent (BGE) considered that the proposal should not go ahead

unless at least the current level of transparency in relation to shrinkage costs can be maintained. That respondent, along with a number of other respondents, expressed the view that GNI should monitor and report regularly on the shrinkage element of the commodity charge if the proposal is adopted. One respondent (BGE) also noted a potential issue that the use of a k-factor to correct for variations between the ex-ante and ex-post cost of shrinkage could result in future customers paying for a previous customer's shrinkage cost, where that previous customer had moved to another supplier. Two respondents (BGE and ESB GT) were also in favour of an incentive on GNI to reduce shrinkage costs. The latter respondent provided the example that National Grid is measured against a market benchmark on its price risk management and assessed on its volume efficiency based on outturn conditions.

In relation to when to implement the proposed changes, some respondents were in favour of implementing in 2019/20 while others considered that it would be more prudent to defer implementation until 2020/21, or later, to allow time for network users to amend their contracts (Shell), for the impacts on revenue recovery to be considered (GNI), and for GNI to revise its IT systems to prepare for the change and for business rules to be put in place (GNI). One respondent (ESB GT) suggested in its response that GNI should 'shadow-charge' for gas year 2019/20 to give network users an idea of how tariffs will be affected by the changes

3.4.3 Response to comments

3.4.3.1 Shrinkage – UAG & OUG

The CRU notes the mixed response to its proposal. Firstly, some comments questioned the compliance of the proposal to classify shrinkage as a transmission service and were of the view that the cost drivers of shrinkage are not capacity and distance.

With regard to compliance, Art. 4(1) of the TAR NC sets out the criteria for distinguishing between transmission and non-transmission services. The defining characteristics of a transmission service are: (a) the costs of such service are caused by the cost drivers of both capacity and distance, and, (b) the costs of such service are related to the investment in and operation of infrastructure that is part of the regulated asset base for the provision of transmission services. Meeting both criteria requires the classification as a transmission service, otherwise there is an option to classify the service as either a transmission service or a non-transmission service.

The CRU is of the view that shrinkage is a transmission service as all network users derive a benefit of the pressures being maintained throughout the system and operated to meet gas flow instructions irrespective of location on the network. In addition, the cost drivers of capacity and distance have a significant effect on the level of shrinkage costs (both OUG and UAG) on the network. The costs of shrinkage (both OUG and UAG) are also related to investment in and operation of the RAB for the provision of transmission services. In addition, ACER in their analysis of the CRU's consultation, agreed with the CRU's assessment of shrinkage as a transmission

service.

Given the above the CRU is of the view that the criteria set out in Art. 4.1 of the TAR NC are met, and as a result shrinkage is a transmission service.

The CRU notes the evidence provided by respondents, which indicates an effect on shrinkage costs depending on the source of supply to the system. The CRU agrees that capacity and distance are not the only cost drivers that effect the total level of shrinkage costs. However, this view doesn't contradict the CRU's classification of shrinkage as a transmission service as capacity and distance are considered to be the most significant cost drivers.

Given the significant costs associated with shrinkage, the CRU considers it important to conduct further assessment (with associated reporting) on what is causing shrinkage. This will help to enhance efficiency in the area of shrinkage, both OUG and UAG. As such, the CRU has requested that GNI carry out a review to examine shrinkage cost drivers further.

3.4.3.2 Effect on power generation

The CRU notes the argument against the shrinkage proposal on the basis that greater flow-based charges are preferable in general to avoid placing a disproportionate weight on power generators. See Section 3.6.3.2 for the CRU's view on the increased capacity element.

3.4.3.3 Transparency & implementation

In coming to its decision on the implementation of the shrinkage proposal, the CRU has also taken into account the issues raised by some respondents regarding a potential loss of transparency in the event the proposal is implemented. The CRU is of the view that it is essential that at least the same level of transparency is maintained. In addition, the CRU notes issues raised (Shipper contracts, TSO billing processes and amendments to the Code of Operations) by stakeholders regarding an implementation date of gas year 2019/20.

One respondent (ESB GT) recommended that in order to provide an indication of the impact of the proposed change that GNI shadow report⁴³ on these costs for the first year. The CRU is of the view that this is a prudent approach. The CRU also considers it prudent to incorporate shrinkage into transmission revenues in the 2020/21 tariff year. This will not only allow time to complete the necessary practical changes (e.g. changes to TSO billing) but it will also allow the CRU time to further engage with Shippers and GNI on shrinkage reporting arrangements in order to develop the appropriate reporting mechanism. This will be progressed with Shippers and GNI through the Code Modification Forum.

⁴³ Reporting to shippers on the costs, as if these costs were included in the transmission services revenue in 2019/20.

The CRU considers that the above approach should ensure a smooth transition to the new charging arrangement and no loss of transparency for stakeholders.

3.4.3.4 Shrinkage incentive

The CRU notes the comments regarding a possible shrinkage incentive. In this regard the CRU noted in the consultation paper that the inclusion of shrinkage in the allowed revenue enhances the ability of the CRU to employ financial incentives around shrinkage volumes when carrying out the next price control, as it currently does with distribution shrinkage volumes. The CRU notes the shrinkage incentive example provided by one respondent and the CRU will consider this example alongside evidence from other international comparators when examining the possibility of including a shrinkage incentive as a part of the next price control process.

3.4.4 Decision

The CRU notes the mixed response to its proposal. The CRU continues to be of the view that shrinkage should be classified as a transmission service as all network users derive a benefit of the pressures being maintained throughout the system and operated to meet gas flow instructions irrespective of location on the network and that shrinkage also meets the criteria set out in Art. 4.1 of the TAR NC. In this regard, ACER's analysis agreed with the CRU's assessment of shrinkage as a transmission service. Based on the above, the CRU has decided that shrinkage will be classified as a transmission service. The CRU has decided that this change will occur for the tariff year 2020/21. This is to ensure sufficient time to conduct the necessary practical changes required for this (e.g. changes to TSO billing systems) but also to develop appropriate reporting mechanisms. For the tariff year 2019/20, the CRU has decided that GNI will shadow report on shrinkage (i.e. reporting as if it was classified as a transmission service).

To be clear, the current arrangements will continue for the gas year 2019/20, i.e. shrinkage costs will be recovered outside of the allowed revenue through a separate flow-based charge to Shippers pro-rata based on their throughput.

CRU Decision

3. The CRU has decided that starting in the gas year 2020/21 shrinkage will be classified as a transmission service.

3.5 Entry/Exit split

3.5.1 Introduction

The revenue to be recovered for transmission services is allocated between entry and exit points. The ratio of this allocation of revenues is known as the entry/exit split. The TAR NC does not have a specific requirement related to the entry/exit split, however it does employ the use of a 50:50 split

in the counterfactual CWD reference price methodology.

3.5.2 Consultation paper and comments

In the consultation paper the CRU considered that the reasoning outlined in its 2015 decision paper for a 33:67 split continues to apply and that maintaining this approach has the advantage of regulatory stability. The CRU proposed to continue to apply an entry/exit split of 33:67 and requested comment from stakeholders.

CRU consultation request for comment

4B. What are your views on the CRU's proposal to continue to apply a 33:67 entry/exit split?

The clear majority of the respondents who addressed this issue were in favour of retaining the 33:67 entry/exit split. Respondents approved of maintaining this split in the interest of stability and noted that the reasons for the selection of this split in 2015 still hold. A respondent (IOOA) expressed agreement but on the basis that the split reasonably reflects the split on the regulated asset base (RAB). One respondent (ESB GT) indicated that greater justification of the cost split may be required to ensure compliance with the relevant ACER guidelines.

One respondent (Tynagh Energy) was opposed to the proposal on the basis that the unavailability of secondary exit capacity offsets the fact that retaining the 33:67 split minimises redistributive effects.

3.5.3 Response to comments

The CRU notes the clear majority of respondents favouring the proposal to continue with the 33:67 entry/exit split, which indicates the suitability of this split, in the context of the Irish gas market. The CRU continues to be of the view that continuing with the 33:67 entry/exit split is in the best interest of gas customers as it maintains regulatory stability and for the reasons set out in the 2015 decision..

Regarding the point made by one respondent (ESB GT) regarding justification of the split in terms of compliance the CRU notes that the TAR NC does not have a specific requirement related to the entry/exit split. However, the CRU notes that the PC4 transmission revenue model (CER/17/134) indicates that the entry/exit split continues to reasonably reflect the RAB split, which also resolves the comment from another respondent (IOOA) in this regard. Finally, with regard to the point made regarding redistributive effects, the CRU notes that the 33:67 split retains the status quo and that secondary exit capacity is currently unavailable. Therefore, retaining a 33:67 split preserves arrangements on both counts (avoiding redistribution).

3.5.4 Decision

The CRU notes the clear majority of respondents favouring the proposal to continue with the 33:67 entry/exit split. The CRU also notes ACER's analysis, which ACER highlighted no compliance issues with the implementation of this split. The CRU is of the view that continuing with the 33:67 entry/exit

split is in the best interest of gas customers as it maintains regulatory stability and for the reasons set out in the 2015 decision.

Given the above, the CRU has decided to continue to apply a 33:67 entry/exit split.

CRU Decision

4. The CRU has decided to continue to apply a 33:67 entry/exit split.

3.6 Capacity/commodity split

3.6.1 Introduction

The TAR NC requires that the transmission services revenue is recovered through capacity-based charges and that flow-based charges, i.e. commodity charges, should only recover the variable costs associated with the quantity of gas transported. This requires revenues to be allocated to these two different charges.

3.6.2 Consultation proposal and comments

In the consultation paper the CRU proposed that maintaining a capacity/commodity split of 90:10 was appropriate. In reaching that view the CRU took into consideration a number of factors. Firstly, the CRU's proposal to recover shrinkage costs through the commodity element of transmission charges makes the 90:10 capacity/commodity split more cost-reflective. This is because it was unlikely that 10% of the transmission services revenue (which doesn't include shrinkage) reflects costs associated with the quantity of gas flowed. Given the importance of the cost-reflectivity principle in achieving a harmonised tariff structure, the CRU stated that this change would ultimately be of benefit.

In addition, the CRU noted that the more cost-reflective approach of incorporating shrinkage costs into the transmission services revenue effectively increases the proportion of charges that are capacity-based and that this rewards those users with a higher load factor, i.e. more stable demand, and may potentially have a negative impact on those with a lower load factor, i.e. residential customers (estimated at less than half of 1% increase on an annual bill) and peaker plants.

The CRU proposed to continue to apply a capacity/commodity split of 90:10 and requested comment from stakeholders.

CRU consultation request for comment

4C. What are your views on the CRU's proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU's proposal to incorporate shrinkage into the transmission services revenue?

A variety of opinions were expressed on this topic, with a majority in favour of the proposal.

Several respondents were fully in support of the CRU's proposal to continue to apply a 90:10 capacity/commodity split. Other respondents stated that the proposal is only appropriate if shrinkage is included in GNI's allowed revenue or alternatively the capacity/commodity split should be adjusted to reflect actual system costs.

One respondent (VEPIL) was of the view that a 100:0 capacity/commodity split is appropriate if own-use gas (OUG) is classed as a non-transmission service. In the case that there was no change (i.e. it remains outside the allowed revenue) a split of 95:5, moving towards 100:0 would be preferable to them.

One respondent (BGE) welcomed further clarity on the CRU's view that inclusion of shrinkage in transmission services revenue would increase the capacity element.

In disagreeing with the CRU's proposal, one respondent (Tynagh Energy) argued for an 85:15 split on their assertion that gas generators now lack certainty as to the extent to which they will run each year due to increases in wind generation. That respondent further stated that a higher weighting towards commodity would also allow power generators to cover their costs as they would be able to bid in the commodity component into market bids and offers.

One respondent (Aughinish Alumina) requested greater transparency on the CRU's plan to adopt a split of 100:0 in the future.

One respondent (ESB GT) agreed with the CRU's proposal but noted that greater justification of the 90:10 cost split may be required to achieve TAR NC compliance.

3.6.3 Response to comments

The CRU notes that the clear majority of respondents favouring this proposal. Below the CRU has further examined the comments which highlighted potential issues with the proposal.

3.6.3.1 Change in the effective capacity/commodity split

One respondent requested clarity on the increase in the capacity element as a result of this decision. The following table provides an illustrative example of this. The table compares the capacity and commodity elements of the transportation costs before and after the CRU decision to include shrinkage in the transmission services revenue. Before the CRU came to this decision, shrinkage was fully recovered through a flow-based charge (0:100 split) separate from the transmission services revenue (90:10 split).

Note: In the table c/c indicates the capacity/commodity split to be applied. The number in €m is the illustrative amount to be recovered. The numbers in the brackets are the allocation of that amount to capacity and commodity charges respectively, based on the capacity and commodity split in the top row.

Table 4: Example: shrinkage decision effect on capacity/commodity elements of transmission costs

| | <u>Shrinkage costs</u> c/c 0:100 | <u>Transmission</u> <u>services revenue</u> c/c 90:10 | <u>Resulting capacity and commodity</u> <u>elements</u> |
|---------------|-------------------------------------|---|--|
| <i>Before</i> | €10m (0:10) | €190m (171:19) | €200m (171:29) |
| <i>After</i> | - | €200m (180:20) | €200m (180:20) |

In the example provided the *before* result is that the total transportation costs of €200m, are recovered through a capacity element equalling €171m and a commodity element equalling €29m. The *after* result is that the total transportation costs of €200m are split 90:10, resulting in a capacity element equalling €180m and a commodity element equalling €20m. In this example €9m of costs have been transferred from the commodity element to the capacity element.

3.6.3.2 Power generation

Regarding the response requesting a greater commodity element, the CRU notes that in its consultation it highlighted that a move to an increased capacity charging element may negatively impact those with a lower load factor, (e.g. more volatile demand, such as peaker plants). However, given the importance of the cost-reflectivity principle in achieving a harmonised tariff structure, the CRU is of the view that the change to a more cost-reflective charging arrangement will ultimately benefit the gas market as a whole. With regard to the comment on bidding costs, the CRU notes that the I-SEM allows gas generators greater flexibility in how they formulate their offers to the ex-ante markets and simple offers to the Balancing Market, and as a result the effect of this change to a greater capacity element may be muted in some I-SEM markets.

3.6.3.3 Future change to the capacity/commodity split

In response to a request for greater transparency regarding plans to adopt a 100:0 split, the CRU notes that at this point it has no such plans to move to a 100:0 split. The CRU assumes that the respondent is referring to the CRU's proposed 100:0 split during the tariff reform process up to 2015. In CER/15/140, the CRU decided to maintain a 90:10 split and stated that it would review this split in light of any future TAR NC requirements. However, the final TAR NC did not include a requirement for a 100:0 split as was envisaged in the draft TAR NC. As part of this decision the CRU has now completed its review of this split, while considering the final TAR NC requirements, and a 90:10 split will apply. The CRU will assess the capacity/commodity split again as part of its periodic (five-year) Art. 26 consultation in accordance with the TAR NC.

3.6.3.4 Compliance

One respondent (ESB GT) raised a point relating to compliance. The CRU notes that it discussed the justification for its proposal in the context of the related compliance criterion of cost-reflectivity, in Section 4.6.3 of the consultation paper. In addition, ACER has since analysed this proposal and considers that the CRU's application of commodity charges is in line with the requirements of the

TAR NC.

3.6.4 Decision

The CRU notes that the clear majority of respondents favouring the proposal to maintain a 90:10 capacity/commodity split. The CRU continues to be of the view that the most appropriate capacity/commodity split is one that is cost-reflective, i.e. the commodity element reflects as best possible the costs associated with the quantity of gas flowed.

Given that the CRU has made the decision to incorporate shrinkage into the transmission services revenue, (Section 3.4) the CRU is of the view that a 10% commodity element reflects the approximate costs⁴⁴ associated with the quantity of gas flowed.⁴⁵ The CRU recognises that incorporating shrinkage into tariffs and continuing with a 90:10 split will, in practice, increase the effective capacity element of Shipper costs. The CRU considers that this is the most appropriate option given the importance of cost-reflectivity in achieving a harmonised tariff structure, and that this change will ultimately be of benefit to network users.

The suitability of a 90:10 split, in the context of the Irish gas market, is further evidenced by the clear majority of respondents favouring this proposal. In addition, ACER, in their analysis of the CRU's consultation, considers that the CRU's application of commodity charges is in line with the requirements of the TAR NC.

Given the above, the CRU has decided to apply a 90:10 capacity/commodity split.

CRU Decision

5. The CRU has decided to continue to apply a 90:10 capacity/commodity split.

3.7 Expansion constant & annuitisation factor

3.7.1 Introduction

⁴⁴ In the consultation paper the CRU stated that it is estimated that the cost of shrinkage in 2018/19 will be approximately €14.7m. If this was to be included in the 2018/19 transmission services revenue it would make up approximately 7.5% of the transmission services revenue, thereby making the proposed 10% commodity allocation much more cost-reflective. The 2.5% difference recovers other costs related to the quantity of gas flowed e.g. CO2 emissions. Also, there are less quantifiable costs captured here such wear and tear on the compressors due to batch flows.

⁴⁵ The CRU recognises that its decision to incorporate shrinkage costs starting in 2020/21 results in the commodity element not fully reflecting the costs associated with the quantity of gas flowed in 2019/20. However, this later implementation time is required to allow the necessary changes (e.g. TSO billing processes) to be undertaken as highlighted in Section 3.4.4. In addition, this provides the benefit of allowing customers further time to understand any redistributive effects, despite the fact that these effects are expected to be minor.

3.7.1.1 Expansion constant

The expansion constant is applied within the Matrix RPM and provides the forward-looking cost signal (a key element of the CRU's decision to apply the Matrix RPM), which reflects the cost of additional incremental capacity at points on the network. The expansion constant provides a numerical value to the cost of expanding the capacity on the system so that one unit of gas can travel over a specified distance. In this context it is expressed as €/GWh/day/km.

To determine the values of an expansion constant, actual evidence of pipeline and compressor capital and operating costs is used. As the GNI system is comprised of both dry (onshore) and wet (subsea) pipelines, there are two separate expansion constants to reflect the different costs associated with each.

3.7.1.2 Annuity factor

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 operate such an asset. In order to calculate the annual revenues an annuity factor is used. The annuity factor uses the capital costs of the assets and takes into account 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 annuity factor is made up of a number of components and the formula is set out in Figure 3. The annuity factor calculated using that formula is applied within the Matrix RPM. Further detail on the components of the formula were provided in Annex 1.3 of the consultation paper.

Figure 3: Annuity factor formula

$$\text{WACC} * \text{pipeline capex} + \text{pipeline opex} + \text{WACC} * \text{compressor capex} + \text{compressor opex} + \text{fuel cost} + \text{depreciation}$$

3.7.2 Consultation proposal and comments

In the consultation paper the CRU proposed to update the expansion constants to reflect the CRU's PC4 decision and the construction of a 50km of twinned pipe between Cluden and Brighthouse Bay in south-west Scotland. Similarly, the CRU proposed that the annuity factor calculation be updated to reflect the latest data, such as the PC4 WACC and the latest gas prices. The results of the update were that the wet expansion constant rose from €8,757 GWh/d/km to €8,783 GWh/d/km, and that the dry expansion constant rose from €7,874 GWh/d/km to €7,810 GWh/d/km. While the annuity factor reduced from 10.5% to 9.8%.

The CRU noted that updating these components would increase their cost-reflectivity and the CRU requested comment from stakeholders. With regard to future updates the CRU stated that the components should remain stable and that a five-year review strikes an appropriate balance

between stability and cost-reflectivity of the inputs.

CRU consultation request for comment

4D. What are your views on the CRU's proposals to update the expansion constant and annuitisation factors?

A majority of respondents were in support of the CRU's proposal to update the expansion constants and annuitisation factor. Several supported the proposal on the basis that it would increase the cost-reflectivity of tariffs.

One respondent (IOOA) approved of the proposed changes on cost-reflectivity grounds but contended that further updates to these parameters were needed. The respondent argued that the expansion constants were too low and did not properly represent the actual cost of projects. The respondent supported this with a quantitative analysis that compares the NTS element for the Foynes entry point with the Corrib Linkline NTS (non-transmission service) element, highlighting the difference between the two as evidence that the expansion constant underestimates the actual project costs. The respondent stated that the expansion constants should either be updated to reflect actual project costs or for the differences to be explained.

With regard to future updates to these parameters, one respondent (IOOA) is of the view that it would be more cost-reflective to update the expansion constants and the annuitisation factor on a yearly basis. In addition, it was argued that the fuel cost component of the annuitisation factor should be based on the actual price paid by GNI for OUG, rather than on NBP prices. By contrast, two respondents (GNI and ESB) expressed the view that updating the annuitisation factor and expansion constant every five years was appropriate in order to balance cost-reflectivity and stability.

One respondent (BGE) approved of the re-indexing of these parameters and of updating the parameters to account for the completion of the twinned pipeline in Scotland, but also argued that it is inappropriate to include opex and fuel costs in the annuitisation factor.

3.7.3 Response to comments

The CRU notes that the majority of respondents were supportive of the CRU's proposal.

The CRU also notes the response that stated the expansion constants were too low, alongside a comparison of the NTS elements⁴⁶ contained in the Matrix RPM for the Foynes and Innisfree entry points with the Corrib Linkline element. Firstly, the CRU notes that the expansion constants

⁴⁶ The NTS elements are estimated on the basis that the pipelines connecting LNG facilities to the transmission network will not be underwritten by the gas customer, and therefore a separate tariff (NTS element) is required to recover the cost of building the pipeline.

have been thoroughly reviewed and developed in consultation with stakeholders through the tariff reform process which concluded in 2015 and have once again been consulted on as part of this consultation and decision process. The CRU decision paper, CER/15/057, lays out the detailed assumptions and approach to the calculation of the expansion constants. It is important to recognise that the expansion constants do not identify the costs of a specific project, but rather take a blended cost of past projects to arrive at a standardised expansion costs that may apply across the network. This includes a blend of a number of pipeline projects constructed by GNI and therefore are expected to reflect actual pipeline costs.

Secondly, the NTS elements were included in the modelling results to provide the total indicative costs for the potential Foynes and Innisfree LNG facilities. These indicative costs include the 'standard' entry tariff derived using the Matrix RPM plus the NTS element, which recovers the costs of a linkline pipeline to the LNG facilities. This approach is consistent with the approach taken for the derivation of the tariff associated with the Corrib gas field, where the entry tariff derived using the Matrix RPM is added to the Corrib Linkline NTS element.

However, as the Foynes and Innisfree linkline elements are not built, the indicative NTS elements for these pipelines are estimated. These elements are estimated by multiplying the expansion constants by the indicative distance for those points and the annuitisation factor. The actual costs would be included within these elements, once known, and these costs would be derived from factors such as agreed pipeline costs, operating costs, depreciation profiles, applicable cost of capital – only when these costs are known would there be a comprehensive NTS charge for the relevant entry point established.

The methodologies used to derive the Corrib Linkline element, see CER/15/141, and the NTS elements in the RPM are different and are therefore not directly comparable. It is not accurate to deduce that the expansion constant is too low simply because the indicative NTS methodology produces an NTS element lower than the actual Corrib Linkline element.

A similar point was raised and responded to in the 2015 decision paper, CER/15/140. The same respondent raised concern that the signals created by the expansion constant do not reflect the tariff that a merchant interconnector would require to transport gas from Great Britain to Ireland. In response the CRU noted that the expansion constants and annuitisation factor as applied to the Matrix RPM are used to calculate tariffs for the GNI system, not for a merchant provider. The remuneration of a merchant interconnector may be based on other inputs, however this would be a matter for a merchant provider and not a matter that should be captured in the tariffs for entry onto the GNI system. For example, the Corrib Linkline element calculation contains a WACC of 7%, compared to a GNI WACC of 4.63%, and the Corrib Linkline element depreciation profile is 19 years, not 50 years in the case of GNI pipelines.

Regarding the comment which highlighted an issue with the inclusion of opex and fuel costs in the annuitisation factor, CRU noted in CER/15/140 that there was broad agreement amongst

stakeholders that at least some fixed opex costs were inevitable once the capital assets are built. As such, there was general agreement that at least fixed operating costs should be included in the annuitisation factor calculations. The annuitisation factor calculation contains both an estimate of pipeline and compressor opex. These estimates are based on GNI's cost estimates for those areas as a percentage of their total opex costs in PC4. These calculations can be examined in CRU/18/247f. In addition, in CER/15/140 the CRU stated that fuel costs are a key cost in the investment decisions in the provision of entry capacity. Fuel costs are a key element of the cost of moving gas to IBP; as such it is a key component of the "distance" cost driver.⁴⁷ If fuel costs were entirely removed from the calculation then this would remove a cost that is clearly associated with entry from the entry tariff differentials, which would need to be remunerated in some other manner. With regard to one respondents (IOOA) view that the actual price paid by GNI for shrinkage should be included in the fuel cost calculation, the CRU firstly notes that given the uncertainty about future gas prices and future utilisation of the GNI compressors, it is important to recognise that the fuel cost component of the annuitisation factor is an approximation. The prices used in the calculation are NBP spot prices. As per the Code of Operations, the price paid by GNI for shrinkage is subject to the shrinkage contract. Any differences between the spot prices and the actual price paid are an outcome of the contractual agreements with the shrinkage provider and are classified as confidential in the context of those specific arrangements. Notwithstanding this, as a test, GNI performed the annuitisation factor calculation with the actual shrinkage prices paid by GNI and they found that there was no material impact on the overall results.

Finally, with regard to future updates to the expansion constants and the annuity factor the CRU notes the mixed responses. As noted in CER/15/057 an important consideration of a forward-looking methodology is the stability of the expansion constant over time. In its decision paper, CER/15/140, the CRU added that any future review of inputs to the methodology should only occur where a significant change in material costs or technology necessitate such a review. The CRU continues to be of the view that the inputs should be stable and has decided that any future reviews will take place as part of the CRU's Art. 26 consultation process, which is expected to take place every five years. It is the CRU's view that this periodic update strikes the appropriate balance of cost-reflectivity and stability.

3.7.4 Decision

The CRU notes that the majority of respondents were supportive of the CRU's proposal. The CRU continues to be of the view that periodically updating the expansion constants and annuitisation factor to reflect the up to date information (i.e. gas prices) is appropriate as it increases the cost-

⁴⁷ In simple terms compressors add the motive power to the molecules of gas; this motive power is reduced by friction in the pipeline. The longer the pipeline the more friction, the more motive power is needed to keep the gas moving along.

reflectivity of these components of the Matrix RPM, and therefore the cost signals that the Matrix RPM sends.

Given the above, the CRU has decided to update the wet expansion constant from €8,757 GWh/d/km to €8,783 GWh/d/km, the dry expansion constant from €7,874 GWh/d/km to €7,810 GWh/d/km, and the annuitisation factor reduced from 10.5% to 9.8%.

CRU Decision

6. The CRU has decided to apply expansion constants of:

wet: €8,783 per GWh/d/km, **dry:** €7,810 per GWh/d/km.

7. The CRU has decided to apply an annuitisation factor of 9.8%.

3.8 Discounts

3.8.1 Introduction

The TAR NC⁴⁸ allows for the adjustment (i.e. discount) of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilities and infrastructure ending isolation.

3.8.1.1 Storage

Art 9. of the TAR NC, states that “A discount of at least 50% must be applied to capacity-based transmission tariffs at entry points from and exit points to storage facilities”.⁴⁹ There are currently no storage facilities in operation in ROI and the CRU is not aware of any plans to develop gas storage infrastructure in ROI.

3.8.1.2 LNG

Unlike storage, Art. 9 of the TAR NC allows for, but does not require, the application of discounts to LNG, with Art 9. 2. stating that “At entry points from LNG facilities, [...] a discount may be applied to the respective capacity-based transmission tariffs for the purposes of increasing security of supply”. There are currently no LNG facilities in Ireland. However, there are LNG projects that could potentially be developed in the future, which the CRU modelled in Scenario 2 and Scenario 3, see Section 2.4.

3.8.2 Consultation proposal and comments

⁴⁸ Art. 9 – Adjustments of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilities and infrastructure ending isolation.

⁴⁹ Unless and to the extent a storage facility which is connected to more than one transmission or distribution network is used to compete with an interconnection point.

3.8.2.1 Storage discounts

In the consultation paper the CRU stated that, although there are currently no storage facilities in operation in Ireland, the CRU would apply at least a 50% discount in accordance with Art.9(1) of the TAR NC, in the event a storage facility becomes operational.

3.8.2.2 LNG discounts

With regard to LNG discounts the CRU stated that it does not have sufficient evidence to determine that an LNG discount would be in the interests of Irish gas consumers at this time. The CRU was of the view that although an LNG facility may provide benefits to Irish gas consumers in relation to security and diversification of supply, it is important to recognise that other supply sources also contribute to Ireland's supply diversity and security. The CRU noted that the proposed Matrix RPM already produces a cost-based investment signal to support efficient new entry to the Irish gas market and that any specific LNG discount would distort the cost reflective investment signals, potentially leading to less effective competition. In addition, the CRU noted that the Matrix RPM balances a range of principles and objectives (including those applied in CER/15/057 and the TAR NC) and so granting any LNG discounts would be expected to have a significant impact on the balance of how these desired properties and principles are achieved within the overall tariff methodology.

However, the CRU stated that it is of the view that it is in the public interest to continue to consider the case for LNG discounts as new information becomes available and that the relative merits of discounts should be assessed on a project-by-project basis following an application from an LNG project developer. The CRU proposed to take into consideration a number of non-binding conditions in order to assess applications for LNG discounts and detailed these criteria in the consultation paper. The CRU requested comment from stakeholders.

CRU consultation request for comment

5A. What are your views on the CRU's proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

A majority of respondents believed either that discounts should not be applied at this time or that discounts should not be applied at any point. The CRU received a mixed response as to whether discounts should be considered in the future.

Some respondents considered that 'straight' discounts are inappropriate and were in favour of the case-by-case approach on the basis that it would allow the CRU to take into account new information and market conditions, assess the relative merits of projects, and determine the impact of individual LNG projects on security of supply and on gas flows from other entry points.

Those respondents opposed to the application of LNG discounts at any time expressed a range of

arguments, including that the security of supply benefits of LNG are not certain, that the Matrix RPM contains an incentive for efficient new entry and that a discount would cause an increase in the wholesale gas price by raising the Moffat tariff. It was also argued that assessing applications for LNG discounts on a case-by-case basis would create uncertainty about tariffs.

Most respondents did not comment on the CRU's proposed criteria for assessing discounts. Two respondents viewed the criteria as reasonable, one respondent considered that both the benefits and the risks of LNG should be considered in any assessment. One respondent (Shannon LNG) indicated its intention to apply for a discount and said that the downward pressure LNG would bring to gas prices should be considered. In a supplemental submission, one respondent (IOOA) noted that the criteria appear reasonable but that the first security of supply criterion was too broad and should be firmly linked to the formal assessment of security of supply.

3.8.3 Decision

Although there are currently no storage facilities in operation in Ireland, the CRU would apply at least a 50% discount in accordance with Art. 9. 1. of the TAR NC, in the event a storage facility becomes operational.

The CRU notes that a majority of respondents were of the view that discounts should not be applied at this time. The CRU continues to be of the view that it does not have sufficient evidence to determine that an LNG discount would be in the interests of Irish gas consumers at this time. For the reasons set out in the consultation paper, and considering views of respondents, the CRU has decided not to apply discounts at this time.

ACER, in their analysis of the CRU's consultation, considers that the CRU's approach to discounts is in line with the TAR NC requirements.

The CRU acknowledges the mixed response as to whether discounts should be considered in the future. Responses highlighted the potential advantages (e.g. security of supply) and drawbacks (e.g. effect on Matrix RPM signals) of applying discounts for LNG and the CRU notes that it has considered many of these points in Section 5.2.2 of the consultation paper and in the development of the assessment criteria. The CRU continues to be of the view that it is in the public interest to continue to consider the case for LNG discounts as new information becomes available and that the relative merits of discounts should be assessed on a project-by-project basis following an application from an LNG project developer. Since the CRU published the consultation paper it has further considered the LNG discount application process and criteria against which the application would be assessed.

Firstly, the CRU has decided on the following application process after considering the timelines associated with the annual tariff setting process. The annual tariff setting process is completed by 31 May of each year ahead of the upcoming gas year beginning 01 October. This process now has to begin earlier to allow the CRU time to assess, consult and come to a decision on the Art 28

requirements (e.g. LNG discounts). As such the CRU requires that a project promoter notify the CRU of an intent to submit an application for a possible LNG facility 18 months in advance of completion of the tariff setting process for the gas year for which a discount is requested. The application should then be submitted in full by 31 May; 12 months before completion of annual tariff setting process. This will provide the CRU the notice period required (12 months) to assess, consult and come to a decision on the application as part of its Art 28. consultation for the coming gas year.^{50,51} In the event that a discount is granted the CRU is required to consult on the level of the discount annually as part of annual Art 28. consultation.

The consultation process and long notice period just outlined will also help to allay the concerns of some stakeholders about the stability of tariffs.

With regard to the criteria against which an application should be assessed, the CRU proposes to take into consideration the following non-exhaustive and non-binding conditions in order to assess applications for LNG discounts:

- The additional security of supply and diversification of supply benefit that an LNG entry point can provide to current and future gas consumers (see discussion below) relative to the cost-based investment signal for entry which is already provided under the Matrix RPM.
- In recognition that other entry points provide security and diversity of supply to the Irish gas market, the CRU may also consider the potential for new entry from other sources of supply, and the corresponding security and diversity of supply benefits that they may provide, when identifying the case for, and level of any discount. This may include proposed alternative LNG facilities.
- The impact of the LNG discount on other entry point tariffs under the RPM. For example, the CRU will consider the increase in tariffs at other entry points, tariff differentials and the resulting diversity premium that the LNG entry point would receive.
- Indirect impacts of the discount on Irish gas consumers, such as the impact on Irish gas prices.
- Any other political, financial or regulatory support which may be provided to LNG developers in order to support entry of an LNG terminal.
- The tariff principles applied in CER/15/140 requirements of the RPM set out in Art. 7 of the TAR NC (see section 3.4.2 for principles).

⁵⁰ This process would determine whether a discount shall be granted, and in the case that a discount is granted what the level of the discount shall be.

⁵¹ For clarity, consider the following example: CRU is notified by a project promoter of intention to submit application by 01 December 2019. Application submitted in full by 31 May 2020. CRU decision on application by 31 May 2021. In the event a discount is granted, it would apply from 01 October 2021.

- Article 41(6)(a) of Directive 2009/73/EC (ensuring viability of networks e.g. revenue recovery)⁵².

With regard any additional security of supply delivered by the LNG entry point, the CRU would expect this to be justified by evidence provided by project promotor(s) as part of analysis of the benefits provided by the new entry point. The CRU will expect project promotor(s) to justify the assumptions and criteria used in their analysis.

For example, one approach could be for the analysis to be based on the ‘N-1’ criterion. In this context, application of the ‘N-1’ criterion may be as follows:

Evidence to demonstrate the security of supply benefit introduced by the new entry point may be defined as the reduction (or elimination) of gas not supplied under a scenario in which the largest piece of gas infrastructure present in the market is assumed to be unable to deliver gas. The quantity of gas that would be delivered by the new entry point that would otherwise not be supplied to the market would be priced based on the value to relevant consumers – e.g. at the value of lost load for gas of the relevant consumers (noting the expected order of system operator actions and (if applicable) the order of disconnection in the event of a gas supply shortfall).

However, other criteria and approaches could be considered by project promotor(s).

As outlined above, the CRU may, in its assessment of a request for a discount, consider the potential for new entry from other sources of supply, and the corresponding security and diversity of supply benefits that they may provide. The CRU would note that this could include consideration of other LNG projects that may or may not have already applied for a LNG discount themselves. In this regard, the CRU will consider the relative incremental impact of each LNG project. Any decision for a discount to apply will be based on this relative impact. This could lead to different discounts being applied to different LNG projects, or to the CRU determining that a discount should not be applied to a LNG project given such considerations.

⁵² Article 41(6)(a) states the following: *“The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for: connection and access to national networks, including transmission and distribution tariffs, and terms, conditions and tariffs for access to LNG facilities. Those tariffs or methodologies shall allow the necessary investments in the networks and LNG facilities to be carried out in a manner allowing those investments to ensure the viability of the networks and LNG facilities;”*

CRU Decision

8. The CRU has decided to apply at least a 50% discount in the event a storage facility becomes operational.

9. The CRU has decided that potential LNG terminals can apply for a discount.

Applications for discounts will be reviewed on a case by case basis

10. The CRU has decided to assess applications for LNG discounts against the non-binding criteria set out in Section 3.8.3, and for that assessment to follow the process set out within the same section.

3.9 RNG transmission entry tariff

3.9.1 Introduction

In addition to potential entry from LNG project developers, Ireland has the potential for new 'small-scale' renewable sources of gas, particularly RNG⁷, which may seek to connect to the transmission system. GNI's strategic plan is to achieve 20% RNG on the network by 2030.

It is therefore important to consider the tariff arrangements which will apply to these new types of entry over the forthcoming tariff period.

3.9.2 Consultation proposal and comments

In NTLG (network tariff liaison group) meetings, RNG developers asked the CRU to consider the development of tariff arrangements for RNG which are simple and pragmatic.

Considering this feedback, the CRU came to the view that it may be appropriate to introduce a single tariff for RNG entry points, and as such proposed a single 'notional entry point' located on the Irish gas system. This would effectively mean that all RNG entry points who wish to connect to the transmission system face an equivalent tariff, regardless of location.

The CRU noted that this reduces the locational signal present within the Matrix RPM, but it considered that this tariffing arrangement has the advantages of simplicity, stability and providing investor certainty.

Further to the above the CRU proposed two possible approaches that could be used to set the location of the single notional entry point:

1. A single notional tariff based on the geographically dispersed locations of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway) transmission entry points, which are included in the model.
2. A single notional tariff based on a location that is close to a demand centre.

In developing the first proposal the CRU considered that RNG, and other small-scale entry is likely

to be located near to the point of production rather than having the flexibility to locate close to demand centres. In addition, while the impacts of the choice of location may be low while volumes of entry are small, the RPM will provide a signal to new small-scale entry points and, as such, it is important that the tariff is broadly reflective of the likely location of new production sources. The CRU was of the view that the three locations in option 1 result in a location that is broadly reflective of these sources (i.e. the Midlands).

In developing the second proposal the CRU considered the importance of incentivising RNG injection given that the industry is currently in its infancy in Ireland. By setting the location of the notional tariff close to a demand centre the reference price for RNG entry would be the lowest possible under the Matrix RPM.

The CRU requested comment from stakeholders on these proposals.

CRU consultation request for comment

5B. What are your views on the CRU's proposal to apply a single notional RNG entry point tariff to all RNG entry points? What are your views on how the notional point should be constituted?

A majority of respondents agreed with the CRU's proposal to apply a single notional entry point tariff to all RNG entry points. Respondents approved of the simplicity and stability of the approach and considered that it would be positive for investor certainty while the RNG industry is in its infancy.

However, one respondent (Green Gas) expressed the view that there should be no RNG tariff as the industry requires incentivisation to compete with natural gas and that RNG provides a standalone benefit by greening the network. This respondent also noted the benefit of avoided compression costs.

Another respondent (Shell) considered that the TAR NC consultation process is not the correct means of incentivising RNG, arguing that a technology neutral approach should be taken, and a separate consultation would be more appropriate. This respondent supported a "geographically dispersed model", with an annual review of the system, if the TAR NC approach is taken.

One respondent (ESB GT) expressed concern that the CRU's RNG proposal may not comply with TAR NC Art. 6.3, which requires all entry points in a system to be treated equally. They also argued that a government subsidy is the best way to support RNG and that neither of the CRU's two proposals effectively captured the likely location of new RNG entry points.

Most of those who commented on the two proposed approaches were in favour of the proposal using a geographically dispersed point. However, some respondents favoured locating the point close to demand while the industry is in its infancy.

Several respondents considered that the CRU should review the RNG tariff as the number of RNG

connections grows.

3.9.3 Decision

The CRU notes that a majority of respondents agreed with the CRU's proposal to apply a single notional entry point tariff to all RNG entry points. The CRU has considered the responses from stakeholders and continues to be of the view that a single notional RNG entry point is in the best interest of the Irish gas market currently as it meets the principles of simplicity, stability and providing investor certainty, which are important for a nascent industry such as RNG. The suitability of this approach, in the context of the Irish gas market, is further evidenced by the clear majority of respondents favouring this proposal. A respondent noted a possible compliance issue with this proposal. The CRU notes that ACER, in their analysis of the CRU's consultation, considers that this approach does create cross-subsidies but that it is allowed by the TAR NC and notes that it is performed for internal competition reasons. As a result of the above, the CRU has decided to apply a single notional RNG entry point approach for RNG.

With regard to the location of the single notional entry point, the CRU notes the mixed response from respondents. The CRU has come to the decision that the most appropriate approach at this time is for the single notional RNG entry point to be a geographic average. The CRU is of the view that this approach is more cost-reflective as it better reflects the likely location of RNG facilities.

The CRU came to the view that the demand centre approach would reduce the costs for this developing industry, however this would not reflect the importance the CRU places on cost-reflectivity and could lead to potential arguments of cross-subsidisation as noted by ACER. In addition, the CRU notes that the Matrix RPM already provides an incentive for efficient new entry and that the RNG entry tariff of €93/MWh is significantly below that of the Moffat entry tariff of €301/MWh, which currently provides the marginal source of gas to Ireland. The CRU is of the view that the single notional point based on a geographic average will support the development of this industry in its infancy by meeting the principles of simplicity, stability and providing investor certainty. In addition, it helps the CRU meet its own strategic priority of delivering sustainable, low-carbon solutions with well-regulated markets and networks in the public's interest.

The CRU notes that the first RNG transmission entry point is now expected in 2020/21 not 2019/20 as was forecasted at the time of the consultation. In response to the comment on future reviews the CRU notes that it will assess the transmission tariffing arrangement for RNG again as part of its periodic (five-year) Art. 26 consultation in accordance with the TAR NC.⁵³ In response to the comment which noted a preference for a technology neutral approach, the CRU notes that RNG is

⁵³ The CRU notes for clarity that although the arrangement will not change, the level of the tariff may vary on an annual basis, as is the case for all entry/exit points reflecting variation in GNI's transmission services revenue from year to year.

currently the only type of low-carbon injection, which is expected to connect to the network. Where additional technologies of this type are developed in the future the CRU will assess this policy. The CRU will continue to consider how it can implement the appropriate policies that will allow the RNG industry to develop effectively, as it has done to date through its RNG connections policy (CRU/18/089) and the recent Code Modification proposal AO94.

CRU Decision

11. The CRU has decided to apply a single notional RNG entry point approach for RNG.

12. The CRU has decided that this single RNG entry point will be based on an average of the geographically dispersed locations of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway).

3.10 RNG distribution entry tariff

3.10.1 Introduction

While not within the requirements of the TAR NC, it is important to consider interactions between the transmission and distribution tariffs for RNG entry points. The first distribution connected RNG injection facility is expected to begin commercial operation in Summer 2019.

3.10.2 Consultation proposal and comments

In the consultation paper the CRU stated that given the small scale of potential new entry projects, producers may be faced with a choice of whether to connect to the transmission or distribution network. The CRU noted that it is therefore important that the transmission and distribution tariffs are aligned so that, to the extent possible, producers face economically efficient signals of the optimum point of connection.

The CRU considered whether a similar notional entry tariff approach should be applied to distribution tariffs and welcomed views on the additional factors which may need to be taken into account in designing such a tariff. The CRU requested comment from stakeholders.

CRU consultation request for comment

5C. What are your views on RNG distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

Many respondents did not express a view on this issue. Amongst those that did, a number of respondents thought that the transmission and distribution tariffs should be designed to produce efficient locational signals to RNG producers as to where to connect to the network. Other factors which respondents believed the CRU should take into account included: any reinforcement costs

needed for distribution-connected RNG to enter the transmission network (GNI), potential interruptions to the supply of RNG on the network (GNI), possible distortions to the Matrix RPM (Manx Utilities), and the fair and equitable development of the gas system (Energia).

One respondent (BGE) considered that there are currently no grounds for a differential between transmission and distribution tariffs for RNG but that the approach taken should be reviewed as the amount of RNG on the network increases.

Another respondent (RGFI) was of the view that distribution-connected RNG should be charged an exit tariff but not an entry tariff and that this arrangement could be reviewed in c. five years. This respondent noted that distribution-connected RNG alleviates the need for transmission system reinforcement by avoiding that part of the network.

3.10.3 Decision

The CRU has examined the responses and has come to the view that further consideration still needs to be given to designing an enduring tariff⁵⁴ for RNG entry at the distribution level. The CRU expects to consult on such a tariff as part of a separate work stream in Q4 2019.

CRU Decision

13. The CRU's decision is to further consult on an enduring tariff for RNG entry at the distribution level as part of a separate work stream in Q4 2019.

3.11 Virtual Reverse Flow

3.11.1 Introduction

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 ROI via Moffat and into ROI via Gormanston.⁵⁵ VRF is a day-ahead interruptible product. The CRU has applied to date an interim charge for use of the VRF service. That charge recovered the cost of developing and administering the VRF service.⁵⁶ There have been a number of discussions regarding the appropriate charge/tariff for VRF at the Code Modification Forums, chaired by the CRU, over the last number of years. At the forums the CRU has highlighted its intent to move to a tariff for VRF, which is based

⁵⁴ Currently, as an interim measure, the entry tariff at the first distribution connected RNG injection facility is designed to recover the operational costs associated with the entry point. The CRU expects this approach to continue until a decision on an enduring RNG distribution entry tariff is made.

⁵⁵ 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.

⁵⁶ For the gas year 2018/19 the CRU continued to set an annual registration fee for the use of this service at Moffat (€15,414) and Gormanston (€40,625).

on the probability of interruption.

3.11.2 Consultation proposal and comments

3.11.2.1 Defining the appropriate firm product

In the consultation paper the CRU proposed that the tariff for use of the VRF service should be set using the principles and requirements in TAR NC for standard interruptible capacity products. The proposal was consistent with charging for use of a single entry-exit transmission system and would provide transparency and predictability to users of the VRF service in relation to how the VRF tariff would be set, using TAR NC principles.

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.

The formula for calculating the adjustment which should be applied is set out in the TAR NC and is as follows:

$$D_{i_{ex-ante}} = Pro \times A \times 100\%$$

Where:

$D_{i_{ex-ante}}$ is the level of an ex-ante adjustment;

Pro Factor is the probability of interruption;

A Factor is the adjustment factor which should reflect the estimated economic value of the interruptible capacity product. The TAR NC restricts the A Factor to being equal to, or greater than one (i.e. it can only increase the level of reduction).

In order to determine the appropriate tariff for VRF following the above process, the appropriate firm product from which to apply an interruptible adjustment must first be decided.

In the consultation paper the CRU stated that the appropriate point on which to base the Moffat VRF tariff should be the Moffat exit point. This is because the Moffat VRF product provides the ability for market participants to book capacity for the commercial flow of gas from Ireland to Great Britain across the Moffat interconnector. Following the same logic, the CRU identified the Gormanston entry point as the appropriate point on which to base the Gormanston VRF tariff, as this VRF service allows the user to virtually flow gas into ROI.

In addition, the CRU proposed that the appropriate firm capacity tariff to which an adjustment should be applied is the relevant day-ahead reference price calculated by the Matrix RPM at the Moffat exit point and the Gormanston entry point. Given that VRF is a daily product the CRU was of the view that multipliers and seasonal factors should be applied in order to reflect the value of short-term products and to reflect the seasonal variation in use of the gas transmission system.

3.11.2.2 Estimating the Pro Factor

GNI calculated the probability of interruption of the VRF product at Moffat from September 2017 to September 2018. This was based on the number of days on which allocations of VRF were recorded but interruptions occurred. In the period September 2017 to September 2018 GNI has calculated that interruptions occurred on 22 of the 275 days in which VRF allocations were recorded. This resulted in a Pro Factor of 8%, see CRU/18/247g.⁵⁷ However, the CRU noted that GNI does not currently have the full suite of data available to calculate the Pro Factor using the methodology set out in the TAR NC. It was proposed that GNI would update the Pro Factor as more data becomes available to GNI.

As the VRF product is not currently in use at Gormanston, it was not possible for GNI to calculate a Pro Factor for Gormanston. As such the CRU was of the view that, until it can be calculated, it would be beneficial to treat the two VRF products on a consistent basis. The CRU therefore proposed to apply the Moffat Pro Factor until the data required to calculate the Gormanston Pro Factor becomes available.

3.11.2.3 Estimating the A factor

With regard to the economic value (A Factor) of the product, the CRU considered analysis of VRF usage and input from stakeholders. From this analysis and engagement, the CRU came to the view that a risk premium factor was likely to be necessary to reflect the reduction in the value of the product beyond the probability of interruption itself. Without having received evidence from the market to indicate what a reflective level of this risk premium should be, the CRU consulted on a risk premium of 10% for both the Moffat and Gormanston VRF products. This level of risk premium was based on precedent in relation to the levels of risk premiums applied to interruptible gas transmission capacity products in a number of European countries⁵⁸.

Having set the risk premium at 10% the CRU then considered what further reductions were required to reflect any interactions with cross-border trade. During this process, the CRU identified interactions between the tariffs applied to the forward flow and VRF products. To help reduce distortions to cross-border trade and to encourage the efficient use of the VRF product, the CRU considered it sensible to ensure that the post-adjustment VRF tariff would be priced lower than the equivalent entry tariff (also reflecting the interruptible nature of the product). The CRU therefore proposed a further reduction of 30% to the A factor. Because the Gormanston VRF tariff would already be lower than the Gormanston Exit tariff, this 'market interaction factor' would apply to the Moffat VRF tariff only. Applying this market interaction factor results in a total reduction of 40% at

⁵⁷ The CRU notes that given the extent of data available, incorporating seasonality into the calculation of the probability of interruption would not be sufficiently well evidenced and thus an annual Pro Factor is proposed.

⁵⁸ Evidence was drawn from interruptible products in Belgium, Denmark, France and Germany.

Moffat. As the A factor is a multiplicative term within the formula, the 40% reduction is achieved by applying an A-factor of 6.

3.11.2.4 Other

In addition to capacity-based tariffs for VRF, the CRU is required to also consider the application of a commodity tariff. As the focus of engagement with stakeholders had been on the development of a capacity tariff, the CRU had not yet come to a view on the application of commodity tariffs for the VRF product. The CRU requested views on whether a commodity tariff should be applied.

Finally, the CRU noted that the indicative VRF prices presented were the annual reference prices to which the multipliers/seasonal factors would be applied to derive tariffs for the daily VRF product.

3.11.2.5 Summary

In summary, the CRU proposed that the VRF tariff should be set following the TAR NC rules for standard interruptible capacity products and that the appropriate firm product from which to apply an adjustment should be the Matrix RPM reference price for the Moffat Exit point and the Gormanston Entry point.

The CRU proposed a risk premium of 10% and a reduction of 30% to reflect market interactions with GB where appropriate. This would result in an A-factor of 6 for the Moffat VRF tariff and an A-factor of 2.25 for the Gormanston VRF tariff.

In addition to capacity-based tariffs for VRF, the CRU requested comment from stakeholders as to whether a commodity tariff should be applied. Finally, the CRU noted that multipliers and seasonal factors would be applied to derive the daily VRF tariff.

CRU consultation request for comment

6A. What are your views on the CRU's proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

6B. What are your views as to whether commodity charges should apply to use of the VRF product?

3.11.2.6 Response to request for comment

With regard to question 6A, the CRU received submissions expressing a range of views on the proposed VRF tariff methodology and the proposed factors to be used in setting the VRF tariff.

Several respondents expressed support for the proposal. This included one respondent (GNI) who considered that the interactions with the VRF product may evolve after the introduction of the new tariff. In light of such, GNI suggested that changes in behaviour should be continuously analysed so that the tariff can be updated annually if needed. There was another respondent (Tynagh Energy), who argued that the costs of an interconnector should be applied proportionally to both

virtual and physical flows and that the status quo (where a low administrative charge is applied) results in forward flow Shippers subsidising VRF-users. One respondent (Energia) welcomed the proposed introduction of the VRF tariff and, while stating that the discounts were 'somewhat generous to VRF', considered that the change would lead to more equitable treatment of Shippers. Another respondent (Electric Ireland) stated that it supported treating VRF as an interruptible product.

A number of respondents (Manx Utilities, BGE, Aughinish Alumina, ESB GT) were in favour of the principle of VRF charging but disagreed with individual elements of the tariff calculation. Almost half of respondents (IOOA, Shannon LNG and Shell) who commented on the issue were opposed to the CRU's VRF proposal. Below the CRU has highlighted comments which take issue with specific elements of the VRF tariff.

Definition of VRF as a transmission service

One respondent (IOOA) argued that VRF should not be treated as a transmission service as the cost drivers are not related to capacity or distance and given its view that the service requires no infrastructure investment in the RAB.

Pro Factor

One respondent (IOOA) took issue with the probability of interruption used in the calculation of the VRF tariff, arguing that the calculation does not account for the fact that VRF offers are constrained by forward flows and the fact that the probability of interruption is likely to be highest when VRF is most in demand, on days when there are low levels of forward flow at Moffat. Another respondent (Aughinish Alumina) questioned the need for the pro-factor given declining Corrib production. One respondent (ESB GT) also contended that the Moffat VRF Pro Factor should not be applied to Gormanston VRF and that the Gormanston VRF Pro Factor should be zero.

A Factor

One respondent (Manx Utilities) was of the view that the calculation of the A factor was unclear.

Another respondent (IOOA) argued that the risk premium of 10% proposed is too low and should be increased because of the lack of options, such as storage, for excess gas in Ireland. Another respondent (ESB GT) contended that the application of the 10% risk premium to Gormanston is inappropriate as the risk premium is 'entirely theoretical' for the Gormanston VRF product.

One respondent (BGE) considered that the 30% discount for the Moffat VRF product was too high. They further contended that the decline of Corrib production and the 'dearth of possible new sources of indigenous gas in the short-medium term' meant such a discount is not presently needed to enable access to the GB market for balancing purposes. In addition, one respondent (Energia) expressed the view that the level of discounts applied to VRF were 'somewhat generous'.

Multipliers

Two respondents (Shell and IOOA) contended that multipliers should not apply to the VRF product as the product is not available on a long-term basis.

Commodity Charges

With regard to 6B and whether commodity charges should apply to VRF products, a majority of responses to this question argued that such charges should not apply. These respondents mostly noted that the product adds no costs to the system. One respondent (IOOA) considered that the product saves costs by reducing OUG.

Three respondents (GNI, Energia, BGE) were in favour of the commodity charge for VRF. One of these (Energia) contended that it was necessary so as to preserve the principles of the tariff regime and minimise distortions in application of the tariff methodology. Another respondent (BGE) considered that the capacity/commodity split for VRF charges should be 90:10 for consistency.

Cost-reflectivity

Several respondents considered that there was a lack of cost-reflectivity in the proposed VRF tariff. One respondent (Shannon LNG) considered that the VRF tariff may be too high as the VRF service brings balancing flexibility to the Irish market without imposing costs. Another respondent (Shell) argued that day-ahead and within-day products should reflect the short-run marginal cost of making capacity available. They considered that there was no such cost for VRF and so capacity charges should not apply. In addition, they expressed a preference for the current registration charge on the basis that it covers the costs associated with providing the VRF service.

One respondent (IOOA) contended that it was inappropriate to use the firm exit charge as the basis for the VRF tariff and suggested that it was perverse that the Moffat exit tariff should be the highest primary tariff on the system. They also took issue with the application of the exit cost-recovery adder to the VRF tariff and proposed that the firm entry tariff could be used as the appropriate tariff on which to base the VRF tariff instead. In addition, they expressed the view that VRF increases GNI's revenues without any additional cost and so tariffing for VRF means "generating an additional k factor" which leads to exports cross-subsidising imports.

Impact on the IBP and the balancing market

One respondent (Shell) suggested that a greater reduction of the tariff is needed so that VRF use is not discouraged and IBP liquidity is not thereby reduced. Another respondent (IOOA) argued that the proposal would disrupt the balancing market and the IBP, including by increasing the basis risk between IBP and NBP prices. One respondent (BGE) considered that IBP liquidity would in fact be threatened by a *lower* VRF tariff.

3.11.3 Response to comments

3.11.3.1 Definition of VRF as a transmission service

The CRU continues to be of the view that it is appropriate to define VRF as a transmission service. Firstly, the CRU would note that ENTSO-G has suggested that VRF should be defined as an interruptible transmission product and ACER has agreed with the CRU's proposed approach to setting a VRF tariff in principle. Secondly, the CRU considers that such an approach is in line with the broader single-system approach the CRU has adopted to setting tariffs. The CRU considers that use of the VRF product is dependent on the existence of the entry/exit system. As such, the CRU considers that VRF users should pay an appropriate tariff for use of the system.

3.11.3.2 Pro Factor

In relation to one respondent's (IOOA) points about the probability of interruption at Moffat, the CRU notes that past historic use of VRF suggests that the likelihood of VRF being constrained due to intended VRF nominations being greater than forward flows is very low. In relation to impacts beyond the likelihood of interruption, the CRU would note that an A Factor is being applied to reflect the estimated economic value of the VRF product (this is discussed in the next section).

In relation to the Pro Factor for Gormanston VRF, there is no historic data on the use of VRF at Gormanston. However, the CRU considers that it is reasonable in the absence of other information, to base the probability of interruption on the experience to date at Moffat. This is based on the fact that neither Moffat or Gormanston are congested and the potential for interruption at both points are more technical in nature.

The CRU acknowledges that even though the Pro factor is being assessed with the best available information, it is appropriate to keep this value under review. In line with the TAR NC the CRU will review the Pro factor each year and consult on its value. This will allow for the inclusion of new data, based on actual usage of the VRF products.

3.11.3.3 A-Factor

In terms of the risk premium, the CRU remains of the view that a 10% risk premium should be applied to the Moffat and Gormanston VRF products. In the absence of strong evidence to support the introduction of a different level, we have drawn from our assessment of the risk premiums applied to interruptible products in a number of cases in Europe. While noting the different risk profiles in Ireland, we also note that the risk premium is actually higher than the Pro Factor (8%) which reflects the probability of interruption. The CRU is of the view that the risk premium therefore provides a sufficient discount to reflect the reduction in value of the VRF product on top of the probability of interruption itself.

The CRU considers that, in the absence of usage data, applying the same risk premium to the Moffat and Gormanston VRF products is appropriate. As noted below, the risk premium will be assessed as part of the annual tariff review and can be updated, if appropriate, based on new usage data.

In reaching a decision on the level of the A-Factor, the CRU has continued to consider the interaction between the forward flow capacity product and the tariff that would be applied to VRF. The interaction between these two products is important in striking an appropriate balance between the commercial positions of shippers flowing gas into Ireland from GB and producers who may use the VRF product to balance positions.

While market characteristics may lead to shorter term fluctuations in the gas price in the NBP and IBP, the CRU considers that, on average, the IBP price is approximately the NBP price plus the costs of transporting gas across the interconnector. This means that, in general it would be expected that the IBP price would be higher than the NBP price.

In the absence of a market interaction factor, the VRF tariff would be priced above the annual forward flow capacity product. In effect, this would mean that users of the VRF product would be paying a premium to flow gas (virtually) from a higher priced to lower priced market. The CRU considers that this cost-differential could have a distortive effect on cross-border trade between Ireland and GB.

Art. 7(e) of the TAR NC requires the CRU to consider the potential for such distortions. On balance, the CRU has therefore decided that including a market interaction factor which ensures that the Moffat VRF tariff is below the annual firm capacity tariff is appropriate. A market interaction factor of 30% ensures that this is the case while providing a little headroom between the two tariffs to allow for movement in the level of the tariffs over time.

The CRU notes that the discount applied to the VRF tariff can be reviewed annually under the provisions of Art. 28 of the TAR NC.

In summary the CRU is of the view that a risk premium of 10% should be applied to both the Moffat and Gormanston VRF products and that a market interaction factor of 30% should apply to the Moffat VRF product only to bring the price below that of the equivalent forward flow tariff for reasons of cross-border trade. Due to the A-Factor being a multiplicative factor, in order to reach these reductions an A-Factor of 6 for the Moffat VRF tariff and an A-factor of 2.25 for the Gormanston VRF tariff will be applied.

3.11.3.4 Multipliers and seasonal factors

As a starting point, the CRU considers that the application of multipliers and seasonal factors should be consistent with the structure of tariffs more generally. However, the CRU has considered whether there are particular reasons why multipliers and seasonal factors should not be applied to the VRF tariff.

In relation to multipliers, the CRU acknowledges that in the case of the VRF product, market participants do not have the option to book longer term capacity than daily capacity. Without the ability to book longer term capacity products for VRF, the CRU considers it inappropriate to apply daily multipliers.

In addition, without the capability to book longer term products, the application of multipliers would mean that VRF users would face significantly higher tariffs than those available to forward flow users who have the ability to book longer term products. This could result in a distortion to cross-border trade.

The CRU therefore considers that there are good reasons why multipliers should not be applied to the VRF tariff.

The CRU does not consider that there is a strong case against applying seasonal factors. To maintain consistency with the tariff structure in other areas, the CRU has therefore decided that seasonal factors will apply to the VRF tariff.

The seasonal factor multipliers are provided in Appendix C.

3.11.3.5 Commodity Charges

The CRU notes the comments regarding the application of commodity charges. In the context of a single entry-exit system, the CRU considers it appropriate that all entry and exit points on the system should contribute equally to system commodity costs. Therefore, the commodity charge will equally apply to the VRF product as at all other entry and exit points on the system. This is consistent with the requirements of the TAR NC Art. 4(3)(ii).⁵⁹

3.11.3.6 Cost reflectivity

In relation to the overall cost-reflectivity of the proposed tariff, as mentioned above, the CRU notes that the VRF service is reliant on the presence of physical infrastructure and forward flows of gas. The CRU therefore considers that it is appropriate that users of the VRF product bear a portion of the costs associated the infrastructure. The CRU further considers that the current administrative charge for the VRF product is not consistent with the single-system approach, as it only recovers the administrative costs associated with providing this service, rather than for use of the single entry/exit system (see earlier discussion).

While the CRU recognises that the proposed tariff is significantly higher than the current administrative charge for use of VRF, the CRU would note that it has indicated a move to a tariff-based approach for a number of years.

In relation to the Moffat VRF product, the CRU continues to consider that the firm exit point is the most appropriate tariff on which to base the VRF tariff. The CRU continues to consider that VRF is an (virtual) exit product and that, in line with the requirements of a single entry-exit system, the interruptible product should be defined consistently with the Matrix RPM. The CRU notes that the

⁵⁹ "A flow-based charge, which shall comply with all of the following criteria: (ii) [...], and set in such a way that it is the same at all entry points and the same at all exit points"

'market interaction' factor applies a further discount to the equivalent firm product to ensure that the VRF exit tariff is lower than the annual Moffat entry tariff to reduce the potential for distortions to cross border trade.

In relation to one respondent's (IOOA) point about the k-factor, the CRU notes that GNI's allowed revenue will not rise due to the VRF tariff. However, tariffs are set to collect an approved amount of revenue based on likely demand. As tariffs are based on best forecasts, the amount collected can turn out to be greater or less than that approved amount. Where this is the case, a k factor is applied to correct for this over or under recoveries in subsequent tariff years (in essence the k factor increases/decreases GNI's in line with the over/under recovery). In relation to VRF, although it is not increasing the revenues of GNI, if it used more or less than predicted it may result in an adjustment through the k factor (as the expected amount of revenue to be collected from the VRF product was not achieved). However, given the limited use of VRF to date any k factor adjustment associated with VRF is anticipated to be small.

3.11.3.7 Impact on the IBP and the balancing market

Some concerns have been raised regarding the impacts on the Irish balancing market which may result from a high VRF tariff. The CRU acknowledges that the introduction of a VRF tariff may increase the costs of balancing and lead to greater use of alternative balancing products, such as the IBP platform, which may be more expensive than the status quo.

Nevertheless, the CRU considers that the status quo VRF product (based on the registration fee) is under-priced and has signalled a move away from this for a number of years.

The CRU notes that the tariff of the VRF product has been adjusted downwards to ensure that it is below the equivalent forward flow tariffs and daily multipliers will not apply. This is considered, on balance, to be an appropriate approach based on the available information and the nature of the product. In practice, it also avoids an even larger increase in VRF costs, ie if these adjustments allowed for under the TAR NC were not included within the tariff.

Nevertheless, the CRU acknowledges some uncertainty in relation to the impacts of the VRF tariff. The CRU therefore considers it important that, to the extent possible, the impacts of the VRF tariff be assessed and revised if negative impacts are identified due to the tariff being either too high or too low. The CRU will work with the Code Modification Forum to establish the factors that could be practically considered in this assessment; including the impact on the IBP.

In terms of comments relating to the basis risk between NBP and IBP, the CRU has noted interactions between markets and determined that the new VRF tariffing arrangement will tie the Moffat VRF price directly to the forward flow price. This will effectively link IBP and NBP prices and should reduce basis risk.

3.11.4 Decision

The CRU has signalled for a number of years that the current interim administrative charge for VRF would be replaced with an appropriate tariff. In the consultation it was proposed to apply a tariff based on the principles and the requirements of the TAR NC for standard interruptible products. ACER agreed with the CRU's proposed approach to setting a VRF tariff in principle. However, other responses to the CRU's consultation were mixed.

The CRU has decided that it is appropriate to apply the TAR NC principles and requirements for standard interruptible capacity products to the Moffat and Gormanston VRF products. Firstly, the CRU continues to be of the view that it is appropriate to define VRF as a transmission service, because, *inter alia*, this approach is in line with the single-system approach the CRU has adopted to setting tariffs.

The Moffat VRF tariff is based on the Moffat exit point reference price and the Gormanston VRF tariff is based on the Gormanston entry point reference price. The CRU has decided that a Pro Factor of 8% should be applied to the Moffat and Gormanston VRF products. The CRU has decided that a risk premium of 10% should be applied to both the Moffat and Gormanston VRF products and that a market interaction factor of 30% should apply 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 of 6 for the Moffat VRF tariff and an A-factor of 2.25 for the Gormanston VRF tariff.

In relation to multipliers, the CRU acknowledges that in the case of the VRF product, market participants do not have the option to book longer term capacity than daily capacity. To apply daily multipliers to VRF may place VRF shippers at a significant commercial disadvantage versus forward-flow shippers. In addition, unlike physical capacity products, VRF can only be booked daily and therefore the benefits of longer-term bookings in relation to reducing volatility of cost recovery do not apply. Based on these considerations, the CRU has therefore decided that, given the special circumstances which relate to VRF products, daily multipliers shall not be applied to the VRF product.⁶⁰ For the avoidance of doubt, seasonal factors shall still be applied to the VRF product in line with the CRU's proposed approach.

In the context of a single entry-exit system, and in accordance with Art.4, the CRU considers that a consistent application of the TAR NC is to apply commodity charges on an equivalent basis at all entry and exit points. Therefore, the CRU has also decided that commodity charges should apply to use of the VRF product.

Overall the CRU has reached what it considers to be a balanced position, which is compliant with the requirements of the TAR NC. At the same time, it should be noted that it is difficult to predict all

⁶⁰ The CRU notes that Article 12 of the TAR NC allows for different application of multipliers for interruptible capacity at interconnection points.

impacts of a proposed tariff. The CRU therefore considers it important that, to the extent possible, the impacts of the VRF tariff be assessed. The CRU will work with the Code Modification Forum to establish the factors that could be practically considered in this assessment; including the impact on the IBP.

Finally, the CRU would note that the level of discounts applied to the VRF products will be assessed as part of the TAR NC Art. 26 annual tariff consultation. This will allow the discounts to be adjusted, if appropriate, based on new information and usage data.

CRU Decision

14. The CRU has decided to calculate a tariff for Moffat VRF and Gormanston VRF based on the TAR NC principles and requirements for standard interruptible capacity products, as set out in Section 3.11.4.

3.12 Multipliers & Seasonal Factors

3.12.1 Introduction

Capacity is auctioned at the IPs and is available to shippers on a first come first serve basis at the non-IP entry and exit points. A reserve price is used to auction the capacity at the IPs.^{61,62} The Matrix RPM sets the reference price, or in simple terms, the tariff for annual firm capacity. For annual firm capacity the reference price is used as the reserve price for the auction. There are a number of additional capacity products which Shippers can book for a shorter period. In Ireland there are quarterly, monthly, daily and within-day capacity products.⁶³

Multipliers and seasonal factors are applied to the reference price to derive the reserve prices for these non-yearly capacity products.

- **Multipliers:** These are used to determine the multiple of the yearly capacity product tariff, which is applied to the relevant non-yearly capacity product to calculate the relevant tariff. The multiplier should be constant for any capacity product type – e.g. all monthly products will have the same multiplier.
- **Seasonal factors:** Seasonal factors are used to derive a profile for the reserve prices of the capacity products across the year. This leads to differentiation of the reserve prices

⁶¹ In Ireland the floating payable price approach is used, for further detail see Annex 1.2 of the consultation paper.

⁶² As there are no auction premiums in Ireland the reserve price is the price paid for the capacity products, in other words, there is no difference between the reserve price and the tariff.

⁶³ As the within-day capacity product is set at the price of the daily capacity product it is not necessary to detail its cost in this section.

for a capacity product at different times of year based on the principle of cost-reflectivity – i.e. that requirements for capacity during periods of high utilisation are more likely to lead to additional network costs and, potentially to requirements for additional infrastructure investment.

The existing multiplier and seasonal factor arrangements have been developed over a number of years. The methodology adopted considers the allocation of historic peak demand days across the months of the year and uses these as a proxy for the probability of incremental demand in that month triggering investment. This implies a monthly tariff profile across the year as a percentage of the annual product tariff. In order to encourage long term bookings, a scaling factor is then applied to increase the relative attractiveness of the annual product in comparison to the short-term products. In addition, while the probability of peak demand days over the summer months was considered to effectively be zero, a minimum tariff was set for these periods.

3.12.2 Consultation proposal and comments

In its analysis, the CRU came to the view that the current interim multiplier for the quarterly product does not provide an appropriate incentive to network users. This is reflected in the lack of use of the quarterly capacity product. To improve the effectiveness of these quarterly multipliers, the CRU proposed to reduce the quarterly multiplier from 1.55 to 1.35.

In its review, the CRU examined two possible options to update the multiplier/seasonal factor profile and presented these options to the NTLG. option one was based on the current methodology. It involved retaining the current seasonal profile spread with a reduction of the monthly multipliers so that their sum came within the bounds of the 1.5 limit set out in TAR NC.⁶⁴

Option two involved deriving the multiplier/seasonal factor profile by applying the methodology which is set out within Art. 15 of TAR NC. In that approach average monthly forecasted flow data were used. This is different to the alternative approach (option one), which was based on historic estimation of occurrence of peak flows. As gas demand in Ireland is relatively consistent throughout the year, the TAR NC methodology based on average flow volumes results in a much more muted seasonal profile. As the occurrence of peak flows has historically only ever occurred in non-summer months and does not occur throughout the year, the CRU methodology results in greater seasonal variation.

In their feedback the NTLG did not consider there to be a need to move significantly away from the current multipliers for non-yearly capacity products or to significantly alter the seasonal profile. As such of the two options presented the NTLG participants preferred option one.

⁶⁴ TAR NC requires that by 31 May 2019, multipliers for quarterly and monthly products are within 1.5 of the annual product and that the daily products are within 3 of the annual product.

The CRU considered the two options in terms of compliance with Art. 28 of the TAR NC. That article seeks to facilitate economic and efficient utilisation of the gas infrastructure and improve the cost-reflectivity of reserve prices. The CRU came to the view that option one was more consistent with Art. 28 as option two would significantly increase the cost of capacity in the summer and reduce costs in winter. This is despite the fact that peak day demands, which have historically occurred during winter, have been the key driver of GNI's system costs.

Based on the NTLG feedback and the CRU's view that option one was consistent with Art. 28 of the TAR NC the CRU sought comments on its adoption.

The TAR NC also includes a possible future requirement for multipliers for daily and within-day products to be limited further to 1.5 of the annual product by 1 April 2023 in the case that ACER makes such a recommendation by 1 April 2021. The CRU requested comment on how it might implement such a change in the event that ACER makes this recommendation.

CRU consultation request for comment

7A. What are your views on the CRU's proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC?

7B. What are your views on the CRU's proposal to reduce the quarterly multiplier to 1.35?

7C. Should a reduction in the range of seasonal factors be considered?

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

3.12.2.1 Monthly multipliers

With regard to reducing the monthly multipliers, all the respondents supported the CRU's proposal to reduce the monthly multipliers to a total of 150% of the annual product to comply with the ACER limits. Respondents generally considered that the proposal was good for stability because it avoided a significant change from the current multipliers.

3.12.2.2 Quarterly multipliers

With regard to reducing the quarterly multiplier to 1.35, a clear majority of respondents were supportive of proposed reduction. Respondents considered that this reduction was prudent in order to incentivise the booking of quarterly capacity.

One respondent (IOOA) cautioned that any reductions beyond 1.35, may reduce annual bookings and in turn increase yearly tariffs. Another respondent (Tynagh Energy) approved of the proposal but was in favour of a further reduction, to 120% of the annual product, so as to properly incentivise quarterly bookings. In addition, a respondent (ESB GT) supporting the proposal was of the view

that any impact of the proposed change on the use of the quarterly product should be monitored and discussed with stakeholders. Similarly, one respondent (Energia) supported the proposal but suggested that these multipliers be kept under review.

3.12.2.3 Seasonal factors

With regard to a reduction in the range of seasonal factors be considered, a clear majority of respondents were opposed to reductions in the range proposed for seasonal factors. Some respondents (IOOA, Aughinish Alumina) expressed concern that such a change would result in system usage shifting to winter from summer, while one respondent (GNI) considered that the current seasonal profile of system usage was appropriate.

One respondent (Manx Utilities) considered that alterations to the seasonal factors should not be considered in the short-term but could be considered if ACER recommended reducing daily multipliers to 1.5 by 2023. Another respondent (Energia) stated that the seasonal factors should not be changed while the effect of the CRU's other proposed changes was being monitored. They suggested that all multipliers, including seasonal factors, should be reviewed periodically. One respondent (ESB GT) was opposed to the proposal to reduce seasonal factors on predictability grounds and also suggested that the CRU should present analysis on seasonal usage patterns and whether they are caused by capacity cost differentials.

A minority of respondents expressed support for reducing the seasonal factors. One of those respondents (Tynagh Energy) contended that the difference between Q1 and summer tariffs had not changed fundamentally in the last decade, while the seasonal profile of gas usage in power generation had moved from Winter to Summer. Another respondent (BGE) argued that a reduction may be necessary to incentivise the use of short-term products and assist the roll-out of flexible generation to complement renewable power generation.

On the same question, a respondent (Electric Ireland) stated that the CRU should reduce the factors if current usage is found to be inefficient. Another respondent (Shell) saw the merit in a reduction of the factors but considered that a transitional approach should be taken if large changes to the factors are needed due to an ACER decision in relation to daily multipliers.

3.12.2.4 ACER alteration to daily multiplier bounds

In relation to question 7D and the potential incremental approach to any changes sought by ACER to multipliers in accordance with the TAR NC, the majority of respondents considered such an approach appropriate. Several respondents were of the view that it would be appropriate to evaluate the effects of any changes required by ACER before they were implemented. They also stated that it would be appropriate to consult on any changes that would have to be pursued due to an ACER direction.

One respondent (GNI) suggested that the CRU should give consideration, *inter alia*, to the fact that

the reduction in the daily multiplier would likely increase the price of annual products and make forecasting more difficult.

One respondent (Tynagh Energy) suggested that, where ACER recommended reducing the daily multiplier to 1.5, the monthly multiplier should be capped at 1.35 and the quarterly at 1.2. In terms of how to implement a reduction in the daily multiplier, one respondent (Tynagh Energy) was of the view that this should be done by increasing the cost of annual bookings, reducing the cost of short-term bookings and reducing the seasonal difference in tariffs.

3.12.3 Decision

The CRU notes the clear majority of support for the proposed changes to the monthly and quarterly multipliers. The CRU continues to be of the view that the most appropriate approach for the Irish gas market is the approach that reduces the current monthly multipliers so that their sum comes within the bounds of the 1.5 limit as set out in the TAR NC. The CRU considers that this approach is more consistent with the requirements of Art. 28 as it incentivises use of the network in the summer; when demand is reduced and more capacity is available. In addition, implementing the TAR NC methodology would lead to a significant change in the seasonal factor profile and considering the responses from stakeholders such a significant change at this time would not be preferred as it creates instability.

The CRU continues to be of the view that reducing the quarterly multiplier to 1.35 is appropriate to incentivise its use and this is further evidenced by the clear majority of respondents favouring this proposal.

A reduction of sum of the monthly multipliers to 1.5 and the quarterly multiplier to 1.35 results in the following table. A breakdown of the multiplier and seasonal factor multipliers into their individual parts is provided in Appendix C.

Table 5: Multiplier profile as a % of annual product (combination of multiplier and seasonal factor)

| 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% |
| <i>Total</i> | <i>135.0%</i> | <i>150.0%</i> | <i>279.44%</i> |

The CRU continues to be of the view that these multipliers and seasonal factors can be refined to

better suit the gas market and the CRU will consult on further changes as part of the annual TAR NC Art. 28 consultation process.

With regard to ACER potentially reducing the daily multiplier limit to 1.5 in the future, the CRU is of the view that such a requirement could have significant impacts. It would likely lead to real effects on the use of different capacity product durations and potentially impact the levels of tariffs and revenue recovery of the TSO. As such, if ACER were to implement such a change, the CRU would consult further with stakeholders and aim to adopt any such change in an approach that is as appropriate and effective as possible.

CRU Decision

15. The CRU has decided on multipliers and seasonal factors, which when combined lead to a price equal to percentage values of the annual product as follows:

| 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% |
| <i>Total</i> | <i>135.0%</i> | <i>150.0%</i> | <i>279.44%</i> |

4 Summary

The CRU has now made a decision on the harmonised transmission tariff methodology for gas having considered responses from stakeholders and ACER's opinion on the CRU's consultation. With the decisions set out in Section 3 the CRU aims to ensure that a harmonised transmission tariff structure exists in Ireland and that the Irish transmission tariff structure continues to appropriately reflect the unique characteristics of the Irish gas network and market, to the benefit of gas consumers.

The decisions reached do not significantly rework the tariff methodology but seek to further refine certain aspects of the methodology so that a harmonised transmission tariff methodology exists in Ireland to the benefit of gas consumers.

In Table 6, the CRU provides a summary of the decisions set out in this paper.

Based on the decisions outlined in this paper the CRU has provided, in Appendix A a table of the final tariffs for the gas year 19/20, alongside the current reference prices in gas year 2018/19. A full list of the indicative reference prices under each scenario considered in the consultation is available in the 'All Results' tab of the RPM excel workbook that was published alongside the consultation paper and is available from the CRU on request.

4.1 CRU decisions

Table 6: CRU decisions

| Topic | Decision | Section |
|---|---|---------|
| RPM | 1. The CRU has decided to continue to apply the Matrix RPM for the calculation of transmission tariffs. | 3.2.4 |
| Non-transmission services | 2. The CRU has decided to continue to classify the Corrib Linkline as a non-transmission service and to continue to calculate the charge for use of the Corrib Linkline in accordance with the methodology in CER/15/141. | 3.3.3 |
| Shrinkage | 3. The CRU has decided that starting in the gas year 2020/21 shrinkage will be classified as a transmission service. | 3.4.4 |
| Entry/exit split | 4. The CRU has decided to continue to apply a 33:67 entry/exit split. | 3.5.4 |
| Capacity/commodity split | 5. The CRU has decided to continue to apply a 90:10 capacity/commodity split. | 3.6.4 |
| Expansion constants and annuitisation factors | 6. The CRU has decided to apply expansion constants of: wet: €8,783 per GWh/d/km, dry: €7,810 per GWh/d/km. 7. The CRU has decided to apply an annuitisation factor of 9.8%. | 3.7.4 |
| Discounts LNG | 8. The CRU has decided to apply at least a 50% discount in the event a storage facility becomes operational. 9. The CRU has decided that potential LNG terminals can apply | 3.8.3 |

| Topic | Decision | Section |
|----------------------------------|---|---------|
| | <p>for a discount. Applications for discounts will be reviewed on a case by case basis.</p> <p>10. The CRU has decided to assess applications for LNG discounts against the non-binding criteria set out in Section 3.8.3, and for that assessment to follow the process set out within the same section.</p> | |
| RNG transmission | <p>11. The CRU has decided to apply a single notional RNG entry point approach for RNG.</p> <p>12. The CRU has decided that this single RNG entry point will be based on an average of the geographically dispersed locations of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway).</p> | 3.9.3 |
| RNG distribution | <p>13. The CRU has decided to further consult on an enduring tariff for RNG entry at the distribution level as part of a separate work stream in Q4 2019.</p> | 3.10.3 |
| VRF | <p>14. The CRU has decided to calculate a tariff for Moffat VRF and Gormanston VRF based on the TAR NC principles and requirements for standard interruptible capacity products, as set out in Section 3.11.4.</p> | 3.11.4 |
| Multipliers and seasonal factors | <p>15. The CRU's decision is to direct GNI to implement the multiplier and seasonal factor profile as set out in Table 3.</p> | 3.12.3 |

4.2 Next steps

The following are the milestones that follow the publication of this consultation:

- Gas year 2019/20 begins – 01 October 2019.

A 19/20 Reference Prices €/MWh

| GNI Transmission Tariffs for 2019/20 | | | Published Tariffs | | | | |
|--|---------|------------------|--------------------------|-----------------|-----------------|----------------|----------|
| 2019/20_T_V7.0 Tariffs | | | 2015/16 Tariffs | 2016/17 Tariffs | 2017/18 Tariffs | 018/19 Tariffs | % Change |
| € | | | € | € | € | € | Nominal |
| | | | from 2018/19 | | | | |
| Exit | | | | | | | |
| capacity | 367.658 | per peak day MWh | 430.882 | 428.352 | 402.080 | 389.884 | -5.7% |
| commodity | 0.216 | per MWh | 0.267 | 0.256 | 0.238 | 0.235 | -8.4% |
| Moffat Entry | | | | | | | |
| capacity | 301.345 | per peak day MWh | 367.786 | 360.253 | 359.183 | 325.979 | -7.6% |
| commodity | 0.103 | per MWh | 0.118 | 0.123 | 0.114 | 0.113 | -8.6% |
| Bellanaboy Entry | | | | | | | |
| capacity | 619.442 | per peak day MWh | 617.996 | 610.463 | 658.431 | 630.428 | -1.7% |
| commodity | 0.103 | per MWh | 0.118 | 0.123 | 0.114 | 0.113 | -8.6% |
| Inch Storage Entry | | | | | | | |
| capacity | | per peak day MWh | 53.058 | 53.058 | 53.027 | 53.027 | -100.0% |
| commodity | | per MWh | 0.118 | 0.123 | 0.114 | 0.113 | -100.0% |
| Inch Production Entry | | | | | | | |
| capacity | 105.557 | per peak day MWh | 164.186 | 156.653 | 156.656 | 123.452 | -14.5% |
| commodity | 0.103 | per MWh | 0.118 | 0.123 | 0.114 | 0.113 | -8.6% |
| Biogas Entry | | | | | | | |
| capacity | 92.775 | per peak day MWh | | | | | N/A |
| commodity | 0.103 | per MWh | | | | | N/A |
| Gormanston VRF Entry | | | | | | | |
| capacity | 65.110 | per peak day MWh | | | | | N/A |
| commodity | 0.103 | per MWh | | | | | N/A |
| Moffat VRF Exit | | | | | | | |
| capacity | 250.044 | per peak day MWh | | | | | N/A |
| commodity | 0.216 | per MWh | | | | | N/A |
| Illustrative Transmission Transportation Costs | | | | | | | |
| € | | | € | € | € | € | |
| Transmission Transportation Cost of UK Gas | | | | | | | |
| capacity | 669.003 | per peak day MWh | 798.668 | 788.605 | 761.263 | 715.864 | -6.5% |
| commodity | 0.319 | per MWh | 0.385 | 0.379 | 0.352 | 0.348 | -8.4% |
| Transmission Transportation Cost of Bellanaboy Gas | | | | | | | |
| capacity | 987.099 | per peak day MWh | 1048.878 | 1038.815 | 1060.511 | 1020.312 | -3.3% |
| commodity | 0.319 | per MWh | 0.385 | 0.379 | 0.352 | 0.348 | -8.4% |
| Transmission Transportation Cost of Inch Production Gas | | | | | | | |
| capacity | 473.214 | per peak day MWh | 595.068 | 585.006 | 558.736 | 513.337 | -7.8% |
| commodity | 0.319 | per MWh | 0.385 | 0.379 | 0.352 | 0.348 | -8.4% |

The table above shows GNI's transmission tariffs for gas year 2019/20, in addition to the transmission tariffs for the preceding four years. The calculations to derive the tariffs for 2019/20 incorporated the decisions set out in this decision paper, as well as current demand forecasts and GNI's adjusted allowed revenue for the year. Further information on the tariffs for the year 2019/20 is given in CRU 19/061.

The forecast overall decrease in the transmission cost of UK gas⁶⁵ in the year 2019/20 is mainly

⁶⁵ This is the Moffat entry tariff plus the domestic exit tariff.

due to the increased demands for 2019/20 and the greater proportion of supply from the Moffat entry point.

B ACER recommendations

B.1 Introduction

ACER carried out an analysis of the CRU's consultation paper pursuant to Article 27(2) of the TAR NC. This review can be found on ACER's website at this [link](#)⁶⁶.

As part of their analysis ACER arrived at a number of recommendations, the CRU has considered these recommendations in the following sections.

B.2 Allowed revenue

B.2.1 ACER recommendation

"Publish the total allowed revenue specifying its transmission and non-transmission shares."

B.2.2 CRU Response

As stated by the CRU in the Section 4.2. of the consultation paper, the "TAR NC defines the allowed revenue as "...the sum of transmission services revenue and non-transmission services revenue...".⁶⁷ To date, when the CRU has referred to GNI's allowed revenue, e.g. its PC4 decision paper and PC4 revenue model, it has reflected GNI's transmission services revenue only, and has not included the non-transmission revenues GNI recover as operator of the Corrib Linkline (see Section 3.3).

*Going forward, in accordance with the TAR NC definition, the CRU will include GNI's transmission services revenue and non-transmission services revenue in its calculation of GNI's allowed revenue. GNI's non-transmission services revenue is negligible, accounting for less than 0.01% of its allowed revenue.*⁶⁸

Recognising that the CRU has not given an absolute figure for the non-transmission services revenue the CRU has now included this information below. The estimated non-transmission services revenue associated with operation of the Corrib Linkline in 2019/20 is €67,084.

⁶⁶https://acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonise-d-transmission-tariff-structures.aspx

⁶⁷ The difference between these services is discussed further in the following section.

⁶⁸ Information on GNI's transmission services revenue is included in the 'Input- Allowed Revenue' tab of the RPM workbook published alongside the consultation paper and available from the CRU on request while a detailed explanation is provided in the CRU's Price Control 4 decision paper (CER/17/260).

B.3 Twynholm transparency

B.3.1 ACER recommendation

“Provide adequate transparency and details on the status of the Twynholm exit point, taking into consideration the existing intergovernmental treaty and underlying transmission agreement. This shall allow clarifying the effect, if any, on cost-reflectivity, non-discrimination, avoiding undue cross-subsidisation, volume risk, and cross-border trade.”

B.3.2 CRU Response

The CRU has provided full transparency on the Twynholm exit point as part of its responses to comment, see Section 3.2.3.3.

B.4 Non-transmission services revenue correction

B.4.1 ACER recommendation

“Explain how the non-transmission over- and under-recovery are addressed.”

B.4.2 CRU Response

As stated by the CRU in the Section 4.3.1 of the consultation paper, the methodology used to derive the Corrib Linkline element is set out in the CRU decision paper Methodology for calculation of the Bellanaboy Entry Tariff (CER/15/141).

Recognising that this does not give the full level of information required to understand how GNI recovers its part of the Corrib Linkline revenue (GNI's non-transmission services revenue), or how over/under recoveries of this revenue are addressed the CRU has included the information below.

To determine the proportion of opex costs of the Corrib Linkline to be allocated to the allowed revenues for GNI the percentage of offtake (exit) flows to overall throughput (entry at Bellanaboy) is calculated and this percentage is then applied to the overall Corrib Linkline opex costs to determine the value for the regulated portion of these costs. With reference to the proportion of volume that are taken off the 'Linkline', this relates to exit flows prior to Cappagh South.

This is calculated prior to the actual flows being realised throughout the year in question – as such, a reconciliation/correction is completed ex-post in the event that the % basis be different to what was assumed at the beginning of that gas year.

B.5 Charges outside scope of TAR NC

B.5.1 ACER recommendation

“Verify that all proposed charges on top of the RPM tariffs are not related to access to the network. If they are instead related to it, they should be recovered via the RPM.”

B.5.2 CRU Response

In accordance with ACER’s recommendation the CRU has further examined these charges. As stated by the CRU in the Section 4.3.2 of the consultation paper, the CRU proposed that the following costs will continue to accrue to the disbursements account on a monthly basis:⁶⁹

- Cost of taking balancing actions;
- Payments/charges to Shippers as a result of Shipper imbalances (Imbalance Commodity Charges and Scheduling Charges);
- Capacity overrun charges incurred by Shippers.

The disbursements account records the reallocation to Shippers of the net cost/income accruing to GNI in accordance with the methodologies set out in the Code so that, over the year, GNI is cash neutral. All these items are allocated according to each Shipper’s throughput as a proportion of the total throughput, except for the capacity overrun charges which are reallocated according to each Shipper’s proportion of the total monthly capacity holdings.

With regard to balancing costs, GNI is obliged to ensure the physical balance of the system and takes balancing actions as it deems necessary to achieve this obligation. GNI takes balancing actions via the trading platform in the first instance and in the event that this is not possible, GNI will take a balancing action in accordance with its Balancing Gas Contract(s), which are awarded following a competitive tender process. Balancing costs include costs associated with use of the trading platform and the buying and selling of gas via the trading platform or balancing gas contracts. Shippers do not incur these costs in order to access the network. In addition, ACER in their review of Denmark’s consultation noted that it agreed with the assessment that the purchase and sale of balancing gas are excluded from the scope of the TAR NC from a joint reading of Articles 3(11), (12) and (15) of the TAR NC. As a result of the above, the CRU is of the view that these charges are not related to access to the network.

With regard to imbalance and scheduling charges, these charges are in place to encourage certain Shipper behaviour (i.e. to be physically in balance on a day and to accurately nominate the gas

⁶⁹ Currently, Shippers are also billed shrinkage commodity and capacity charges on a monthly basis, which includes stock movements/UAG. In accordance with the decision in Section 3.4.4, from 2020/21 these costs will be included in GNI’s allowed revenue.

flowed at entry or exit). Shippers do not incur these costs in order to access the network. In addition, ACER in their review of NI's consultation noted that imbalance charges are excluded from the allowed revenues by virtue of the joint reading of Articles 3(11), (12) and (15) of the TAR NC, and that scheduling charges can be considered administrative fees that apply in case of a difference between the final allocation and the nomination at an exit point. As a result of the above, the CRU is of the view that these charges are not related to access to the network.

Finally, a Shipper incurs a capacity overrun charge where it uses capacity in excess of its applicable capacity. Overrun charges are calculated on quantity of the capacity used in excess of the active capacity. Currently, the overrun charge is eight⁷⁰ times the daily charge subject to maximum annual caps. This charge is in place to encourage certain Shipper behaviour (i.e. for Shippers to not exceed their reserved capacity), Shippers do not incur these costs in order to access the network. In addition, ACER in their reviews of the Greek and Czech consultations noted that the former has a charge for exceeding reserved capacity, and the latter has capacity overrun fee, and in both cases, ACER was of the view that these charges/fees did not fall within the scope of the TAR NC. As a result of all of the above, the CRU is of the view that these charges are not related to access to the network.

⁷⁰ Code Modification AO98 is currently being progressed and proposes to reduce the charge to four times the daily charge.

C Multipliers and Seasonal Factors

In Section 3.12.3 the CRU decided on multipliers and seasonal factors. These were presented in combination as percentage values of the annual product. A breakdown of these elements is provided in the tables below.

C.1 Multipliers

| Capacity Product | Product multiplier |
|-------------------------|---------------------------|
| Annual | 1 |
| Quarterly | 1.35 |
| Monthly | 1.5 |
| Daily | 2.794383812 |
| Within day | 2.794383812 |

C.2 Seasonal factors

| Month | Seasonal multiplier |
|--------------|----------------------------|
| January | 0.007130052 |
| February | 0.008148629 |
| March | 0.006111473 |
| April | 0.002291803 |
| May | 0.000173158 |
| June | 0.000173158 |
| July | 0.000173158 |
| August | 0.000173158 |
| September | 0.000173158 |
| October | 0.002291803 |
| November | 0.002291803 |
| December | 0.004074316 |