An Coimisiún um Rialáil Fóntais

Commission for Regulation of Utilities

Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Call for Evidence

Gas year 2020/21

Call for Evidence Paper

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CRU Mission Statement

The CRU's mission is to protect the public interest in Water, Energy and Energy Safety. The CRU is guided by four strategic priorities that sit alongside the core activities we undertake to deliver in the public interest. These are:

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

Executive Summary

Gas Networks Ireland (GNI) 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. These tariffs allow GNI, as the network operator, to recover the annual revenue set by the CRU to operate the network in a safe and efficient manner.

As part of the annual tariff setting process, the CRU is required under Article 28 of the European Tariff Network Code to consult on the following:

- Levels of multipliers and seasonal factors;
- Levels of discounts (e.g. discount for Virtual Reverse Flow).

The role of these items in the tariff setting process are as follows:

- **multipliers and seasonal factors are applied to calculate the tariffs for non-annual products**: The CRU's transmission tariff methodology sets the tariffs for annual capacity at the transmission entry and exit points. In order to calculate the tariffs for non-annual capacity products (i.e. quarterly, monthly, daily) the annual tariffs are combined with multipliers[1] and seasonal factors[2]. Therefore, the levels of these factors determine the

[1] Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual capacity product to calculate its tariff. For example, the monthly multiplier is 1.5, which means that buying monthly capacity for each month in the year will cost 1.5 times more than buying the annual capacity product.
[2] Seasonal factors are used to create a profile for the non-annual capacity products across the year. This leads to different prices for a non-annual capacity product at different times of year. For example, the monthly product is more expensive in the winter but is cheaper in the summer.

tariffs for the non-annual capacity products. The multipliers & seasonal factors are set to incentivise certain behaviour among gas system users.

- **Setting the cost of virtual reverse flow**: The Tariff Network Code allows for discounts. Currently a discount is only applicable for Virtual Reverse Flow (VRF).[3] VRF is a 'reverse flow' service offered on a virtual interruptible basis, at the Interconnection Points, to enable Shippers to virtually flow gas from Ireland via Moffat and into Ireland via Gormanston.[4] VRF is a day-ahead interruptible product. As it is an interruptible product it receives a discount. Therefore, the level of the discount, amongst other things, determines the level of the VRF tariff.

Last year, the CRU reviewed the multipliers and seasonal factors. The CRU considered updating the multiplier & seasonal factor methodology to a prescriptive (but not mandatory) methodology set out in the network code. Following consultation, the CRU decided against that approach and changed the methodology that was already in place. The changes were minor and were to ensure compliance with the network code and its principles. Those minor changes saw the multipliers and seasonal factors being set as follows.[5]

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

The above factors and a new tariffing approach for VRF came into force on 01 October 2019. As such, they have not yet been in place for a full gas year (01 October 2019 to 30 September

[3] The tariff network code requires that discounts are provided for storage facilities and that they may be applied for LNG facilities, however these do not currently exist on the Irish network.
[4] 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.
[5] To understand how this works, consider the following example: The reference price for Moffat entry is €301/MWh. If you wanted to book monthly capacity for December, you could calculate the cost by referring to the table and applying the relevant combined multiplier & seasonal factor; in this case 17.08%. That would result in the following – €301/MWh * 17.08% = €51.4/MWh.

2020). As the dynamics in the gas market change over the course of the year (e.g. demand levels vary from Winter to Summer due to differences in heating requirements), the CRU considers that it is important to collect a full year's worth of data before making any changes, particularly in the case of VRF as it underwent a significant change in tariffing approach. In addition, the seasonal factors change the cost of the VRF product throughout the year and the CRU has yet to see the impact of the full range of these costs on VRF use.

The CRU has identified the need to build on the work done as part of last year's review and for there to be consideration of wider market changes in any review of multipliers and seasonal factors. For example, there has been a changing role for gas in power generation. Gas plant is now more regularly called upon to support intermittent renewable generation, therefore the gas power sector might benefit from a change in the multipliers which reduce the costs associated with using the gas network on a more flexible basis. However, this change may have an impact on other types of network users and therefore needs careful consideration. In addition, there needs to be consideration of the broader transition to decarbonise the gas network. It will take time for Gas Networks Ireland and the CRU to undertake a thorough review of these factors in the context of market dynamics and the wider gas market developments. It will also require effective input from industry. This thorough review could not be completed in time for the 2020/21 gas tariff setting process.

In addition, the increased uncertainty that the Covid-19 pandemic has brought must be considered. The CRU considers that stability for consumers and industry at this time is likely to be beneficial. The CRU has taken a number of measures to provide appropriate protection and reassurance for electricity and gas customers during the current period of uncertainty[6,7], and will continue to monitor developments. The CRU is committed to continuing to work with industry stakeholders and consumers during the Covid-19 pandemic.

As a result of all of the above, the CRU has decided that there will be no change to multipliers, seasonal factors and VRF for gas year 2020/21. This will allow for additional analysis and a thorough review ahead of the next Article 28 consultation for gas year 2021/22. For the review of multipliers and seasonal factors, the CRU is proposing the following review criteria as set out in the tariff network code:

(a) for multipliers:

(i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;

[6] https://www.cru.ie/cru-announces-covid-19-customer-protection-measures-to-assist-consumers/
[7] https://www.cru.ie/cru-extends-covid-19-customer-protection-measures-to-assist-consumers/

(ii) the impact on the transmission services revenue and its recovery;

(iii) the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices;

(iv) situations of physical and contractual congestion;

(v) the impact on cross-border flows;

(b) for seasonal factors:

(i) the impact on facilitating the economic and efficient utilisation of the infrastructure;

(ii) the need to improve the cost-reflectivity of reserve prices.

In reviewing the value of multipliers and seasonal factors against the above criteria, the CRU will also consider the changing role of gas. As such, the CRU is not only calling for feedback as to whether we should include more criteria in our review but is also seeking submissions on how the use of the gas network is evolving. For example, gas fired electricity generators may have important insights as to how their roles have been involving in the electricity wholesale market and the impact of multipliers and seasonal factors on that role. Gas shippers and businesses may also have insights as to new uses for gas, for example the use of compressed natural gas in transport. In addition, feedback from other users of the gas network is equally important as changing multipliers may change the costs that they face. For example, gas shippers will have data as to how they purchase gas and the impact of multipliers and seasonal factors on that approach.

To aid in responding to this document, the CRU has presented some initial analysis under the proposed review criteria (contained in the appendix). Stakeholder responses will be incorporated into the review to ensure that the review examines the issues important to stakeholders. As such, these responses may be used to support any proposed changes to the multipliers and seasonal factors, which will be consulted upon in time for the gas year 2021/22. The CRU aims to publish a consultation in early 2021 to ensure that any changes brought about by a CRU decision can be incorporated into the methodology time for gas year 2021/22.

In terms of the VRF discount, the CRU is taking this opportunity to gather the views of stakeholders on initial analysis conducted by the CRU and would welcome insights from respondents on the CRU's analysis, the factors which significantly affect the use of and any relevant information network users may have on the commercial value of VRF. This is important because the VRF discount takes into account the economic value of the product. The CRU can then incorporate this data into its analysis of the VRF discount and will consult on any proposed changes to the discount in early 2021.

Public/ Customer Impact Statement

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 public interest. These tariffs allow GNI, as the network operator, to recover the annual revenue set by the CRU to operate the network in a safe and efficient manner.

Last year the CRU completed a review of how transmission tariffs are set. As part of that review, the CRU altered the value of multipliers, seasonal factors and levels of discounts. These items impact the price paid by companies using the gas network and the way in which these network users are incentivised to use the network. These costs may be passed on to the final customer. As such, it is important to keep the value of multipliers, seasonal factors and levels of discounts under review to ensure that they are set appropriately.

As these alterations have not yet been in place for a full gas year (01 October 2019 to 30 September 2020), the CRU does not yet have the full suite of evidence to assess the extent of its decision. It is important to collect a full year's worth of data before making any further changes, in order to avoid unintended consequences. The CRU and GNI have also identified the need to undertake a thorough review of multipliers and seasonal factors in the context of wider market changes (e.g. the role of the gas network in the energy system and decarbonisation of the gas network). This thorough review could not be completed in advance of the 2020/21 gas tariff setting process.

In addition, the increased uncertainty that the Covid-19 pandemic brings about must be considered. The CRU considers that stability for consumers and industry at this time is likely to be beneficial. The CRU has taken a number of measures to provide appropriate protection and reassurance for electricity and gas customers during the current period of uncertainty, and will continue to monitor developments and is committed to continuing to work with industry stakeholders and consumers during the Covid-19 pandemic.

As a result, the CRU has decided to not change the multipliers, seasonal factors and levels of discounts for the next gas year, which runs from 01 October 2020 to 30 September 2021. As there will be no changes to these items, this decision should not impact on the average annual residential customer's bill. This paper seeks comments on the approach to the review and the CRU's initial analysis/ considerations. It also seeks submissions on the evolving use of the gas network; for example, from gas fired generators or those proposing to use the gas network to provide natural gas as a transportation fuel. These comments will provide evidence to support any proposed changes for the 2021/22 gas tariff year. Any changes will be consulted upon.

Table of Contents

Glossary of Terms and Abbreviations

Abbreviation	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
Art.	Article
EU	European Union
GB	Great Britain
GNI	Gas Networks Ireland
I/C	Industrial/Commercial
IBP	Irish Balancing Point
IP	Interconnection Point
SEM	Single Electricity Market
LNG	Liquefied Natural Gas
NBP	National Balancing Point
PC4	Price Control 4
RPM	Reference Price Methodology
SAP	System average price
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

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 customers. Our goal is to ensure that gas is safely and securely supplied and that the charges are fair and reasonable. This paper relates to factors impacting on transmission tariffs.

1.2 Background

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 five-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 five-year Price Control period started on 01 October 2017 (PC4). Allowed revenues for the transmission and distribution systems are set out separately.

Given that the price control is over five years, there is a process for updating the revenues each year to ensure that the most up to date information is being used. As part of the annual tariff setting process, the CRU analyses any additional revenue requests from GNI, over/under recoveries of revenue in the previous years and updated demand projections in order to calculate tariffs for the forthcoming gas year. As part of that process, the CRU consults annually on certain elements feeding into the tariff setting process. This annual consultation is a new requirement and stems from European requirements set out in the Tariff Network Code. The aspects that are consulted upon relate to transmission tariffs only and are:

- Levels of multipliers;
- Levels of seasonal factors;
- Levels of discounts for storage and LNG; and,

- Levels of discounts for interruptible capacity products (i.e. Virtual Reverse Flow).

This paper is seeking comment on those factors excluding LNG and storage facilities, the rationale being, there are currently no LNG or storage operators using the system and therefore no discount is applicable. An LNG operator can apply to the CRU for such a discount and the CRU will consult on its application.

More detail as to the overall tariff setting process, what these factors are, and the European requirements are provided in the following sections.

1.2.1 Allowed transmission revenues & transmission tariff setting

The following is a description of the tariff setting process.

The allowed revenue for the transmission system is split into transmission services revenue and non-transmission services revenue.[8] The transmission services revenue is then inputted into GNI's transmission tariff model (i.e. Matrix reference price methodology (RPM), see following section for further information) to calculate the capacity and commodity charges for each entry and exit point (points where the gas is brought onto and taken from the transmission system).

Entry capacity charges are paid to reserve the right to flow gas into the system up to an agreed flow rate, while exit capacity charges are paid to reserve the right to offtake gas from the system up to an agreed flow rate. Once capacity has been booked, network users can then transport (via GNI) gas on the network for delivery to end users. Commodity charges are paid by network users for use of the system and are based on the actual amount of gas entering and exiting the system. These capacity and commodity charges 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.

The capacity charges calculated by the Matrix RPM are known as references prices and are calculated on the basis of shippers booking a fixed capacity across the entire year (i.e. annual capacity). However, it is possible to book capacity over shorter periods (e.g. book for a month or

[8] 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 reference price methodology (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." GNI earns a small portion (<0.01% of allowed revenue) from non-transmission services, this revenue is associated with the operation of the Corrib Linkline.

a day). To set the prices of these non-annual products, so called multipliers and seasonal factors are applied.

- Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual capacity product to calculate its tariff. For example, the monthly multiplier is 1.5, which means that buying monthly capacity for each month in the year will cost 1.5 times more than buying the annual capacity product. It is more expensive to book these non-annual products, as these products provide more flexibility and can potentially increase system costs for the reasons highlighted in section 2.
- Seasonal factors are used to create a profile for the non-annual capacity products across the year. This leads to different prices for a non-annual capacity product at different times of the year. For example, the monthly product is more expensive in the Winter but is cheaper in the Summer. The cost is more expensive in Winter as there is more demand on the system and this high demand can lead to increased system costs (e.g. building additional capacity), while the cost is less in the Summer to incentivise increased utilisation of the network, which increases system efficiency.

The tariffs for the non-annual capacity products are calculated by multiplying the reference prices / annual capacity tariffs by the above multipliers and seasonal factors. They lead to capacity prices that vary depending on the length of the product chosen and the time of the year in which it is booked. In contrast to capacity charges, commodity charges / tariffs are the same regardless of the time of year or duration of gas flow.

A requirement (Art. 28 of TAR NC) has been introduced to consult on multipliers and seasonal factors annually. This is discussed more in the next section. There is also a requirement to consult on any discounts that may be applied to the reference prices. This is discussed more in section 3.

1.2.2 Gas transmission tariff methodology reviews

In June 2019 the CRU, following a public consultation, published a decision (CRU/19/060), setting out the current gas transmission tariff methodology. The CRU undertook that review to fulfil EU tariff network code requirements (more specifically, European Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas[9]). The EU Tariff Network Code, referred to as TAR NC, was developed with

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

the objective of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks.[10]

The June 2019 decision was the first time the CRU completed a TAR NC Article 26 and Article 28 review. Article (Art.) 26 of TAR NC requires the CRU to review and to consult on the RPM being applied in Ireland at least every five years. Art. 28 requires the CRU to review and to consult annually on aspects of the tariff setting methodology such as those relating to discounts, multipliers and seasonal factors.

The review last year resulted in some minor adjustments to the tariff setting methodology, which is referred to as the Matrix Reference Price Methodology or Matrix RPM.

The minor adjustments were conducted not only to achieve compliance with TAR NC but also to improve the methodology to the benefit of the gas industry in Ireland. ACER individually assessed each NRA's consultation and provided recommendations for consideration in each NRA decision.[11]

On 06 April 2020 ACER published a report[12], which summarised its overall findings and included individual country sheets which detailed, amongst other things, how the CRU and other NRAs implemented ACER's recommendations. Table 1 in the Ireland country sheet included in ACER's report highlighted that the CRU's decision achieved full compliance with the network code.

With this paper the CRU is now carrying out its second annual Art. 28 review.

1.3 Purpose of this paper

This call for evidence paper contains an examination of a number of aspects of the tariff methodology as required by Art. 28 of TAR NC, these are summarised below:

- Levels of multipliers;
- Levels of seasonal factors; and,
- Levels of discounts for interruptible capacity products (i.e. Virtual Reverse Flow).

[10] 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. TAR NC is aimed at overcoming such issues. Specifically, TAR NC aims at increasing the transparency of transmission tariffs and the methodologies used to set these tariffs.
[11]ACER's analysis of the CRU consultation is available at this clickable link.
[12]ACER's implementation monitoring report is available at this clickable link.

1.4 Related documents

Some documents related to this publication are provided below:

- CRU Decision Paper on Harmonised Transmission Tariff Methodology for Gas (CRU/19/060);
- CRU Consultation Paper on Harmonised Transmission Tariff Methodology for Gas (CRU/18/247);
- ACER's analysis of the CRU consultation is available at this clickable link;
- ACER's implementation monitoring report is available at this clickable link
- 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 Matrix model and simplified 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 call for evidence paper is structured in the following manner:

- Section 1 provides an introduction and background, the purpose of this paper, related documents and how to respond to this call for evidence.
- Section 2 examines the levels of multipliers and seasonal factors used to derive tariffs for non-yearly capacity products.
- Section 3 examines the levels of discounts.
- Section 4 provides a summary and next steps.
- Appendix A provides the CRU's initials considerations on the levels of multipliers and seasonal factors.

1.6 Responding to this paper

The CRU invites responses to the questions set out in this paper by 14 July 2020, preferably by email to gasnetworks@cru.ie. Alternatively, responses can be sent to:

Gas Networks Team,
Commission for Regulation of Utilities,
The Exchange,
Belgard Square North,
Tallaght,
Dublin 24.

The responses will be assessed and may be used to support proposed changes to the multipliers and seasonal factors which will be consulted upon in time for the tariff year 2021/2022. Submissions on any of the points listed in this paper should be clear and specific, with analysis or rationale provided to support the views provided. Unless marked confidential, all responses may be published on the CRU's website. Respondents may request that their response is kept confidential.

The CRU shall respect this request, subject to any obligations to disclose information. Respondents who wish to have their responses remain confidential should clearly mark the document to that effect and include the reasons for confidentiality.

Responses from identifiable individuals will be anonymised prior to publication on the CRU website unless the respondent explicitly requests their personal details to be published.

Our privacy notice sets out how the CRU protect the privacy rights of individuals and can be found here.[13]

[13] https://www.cru.ie/privacy-statement/

2 Multipliers & Seasonal Factors

Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual[14] capacity product to calculate its tariff. It is more expensive to book these non-annual products, as they provide more flexibility. This flexibility can potentially increase system costs as longer-term capacity bookings make it easier for GNI to identify periods of peak demand and plan for additional system investment where required. Also, shorter-term bookings can lead to increased revenue recovery volatility.

Seasonal factors are used to create a profile for the non-annual capacity products across the year. The profile sets different prices for a non-annual capacity product at different times of year. For example, the monthly product is set to be more expensive in the Winter and cheaper in the Summer. The cost is more expensive in Winter as there is more demand on the system and this high demand can lead to increased system costs (e.g. building additional capacity), while the cost is less in the Summer to incentivise increased utilisation of the network, which increases system efficiency.

In the interests of simplicity, the CRU has in previous decisions presented the multipliers and seasonal factors on a combined basis. See Table 1, which sets out the current combined multiplier & seasonal factor profile. This table presents the profile as a percentage of the reference price.

To understand how this works, consider the following example: The reference price for Moffat entry is €301/MWh. If you wanted to book monthly capacity for December, you could calculate the cost by referring to Table 1 and applying the relevant combined multiplier & seasonal factor; in this case 17.08%. That would result in the following – €301/MWh * 17.08% = €51.4/MWh.

Table 1: Combined multiplier & seasonal factor profile as a % of annual product

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%

[14] In Ireland the non-annual products are quarterly, monthly, daily and within-day. 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.

Month	Quarterly %	Monthly %	Daily %
July	2.61%	0.97%	0.05%
August		0.97%	0.05%
September		0.97%	0.05%
Total	*135.0%*	*150.0%*	*279.44%*

The existing multiplier & seasonal factor methodology has been developed over a number of years by GNI and the CRU. They are based on, amongst other things, the principle of cost-reflectivity – i.e. that requirements for capacity during periods of high utilisation (peak demand days) are more likely to lead to additional network costs and, potentially to requirements for additional infrastructure investment through reinforcing the network and building additional capacity.

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 those periods.

In accordance with Art. 28 of TAR NC the CRU is carrying out its annual review on multipliers & seasonal factors. More specifically, the CRU has decided not to change the multipliers & seasonal factors for reasons set out in section 2.2, rather the CRU is seeking input on a major review of multipliers & seasonal factors, which will be completed in time for the tariff year 2021/2022. However, before discussing the CRU's review of multipliers & seasonal factors further, it is important to highlight the recent work that was completed in the 2019 review, as this provides the basis for the forthcoming work.

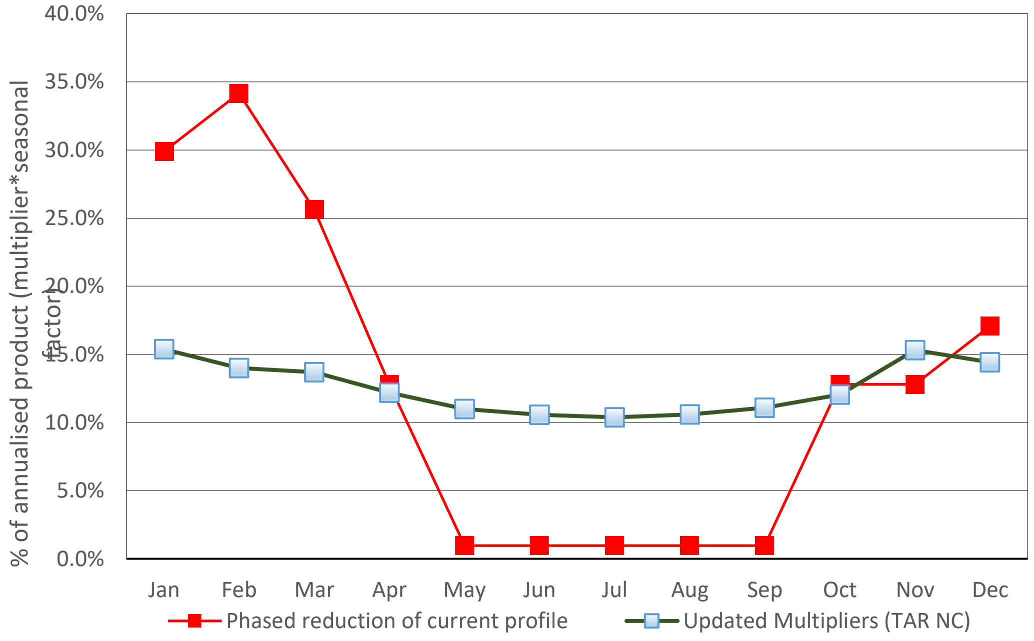
2.1.1 CRU TAR NC 2019 review

As part of the 2019 review, the CRU examined two possible approaches to updating the multiplier & seasonal factor profile.

The first approach was based on the existing peak demand day methodology employed by the CRU, it retained the seasonal profile range but reduced the monthly multiplier slightly so that the sum of the individual monthly products was 1.5 times the cost of the annual product, which is at the upper bound of the 1.5 limit as set out in TAR NC.[15]

The second approach involved deriving the multiplier & seasonal factor profile by applying a prescriptive methodology set out in Art. 15 of TAR NC. The TAR NC approach is based on monthly flow data. That approach would have been a change from the methodology applied in Ireland, which is based on the historic occurrence of peak demand on the network. The TAR NC approach uses average flow volumes, resulting in a much more muted seasonal profile (averages reduce the effect of extremes). 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. The clear difference in the methodologies can be seen in Figure 1.

Figure 1: Reduction of current profile to within TAR NC bounds (first approach) vs TAR NC multiplier calculation (second approach)



The CRU considered the two approaches in terms of compliance with TAR NC. Although TAR NC sets out a prescriptive methodology in Art. 15, it also states in Art. 28 that the NRA needs to take into account consultation responses and that multipliers and seasonal factors should seek to, amongst other things, facilitate economic and efficient utilisation of the gas infrastructure and improve the cost-reflectivity of reserve prices.

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[15] TAR NC requires that multipliers for quarterly and monthly products are less than 1.5 times the annual product and that the daily products are less than 3 times the annual product.

In CRU/19/060, the CRU decided to implement the first approach as it had strong support from respondents and appeared to be more consistent with the principles of Art. 28. For example, the consistent flow profile throughout the year in Ireland may indicate that the methodology is incentivising efficient utilisation of the infrastructure (i.e. relatively similar levels of use in Summer and Winter).

However, the CRU stated that it continued to be of the view that multipliers & seasonal factors can be refined to better suit the Irish gas market and that the CRU will consult on further changes as part of the annual TAR NC Art. 28 consultation process.

2.2 Decision & call for evidence on multiplier & seasonal factor review

In accordance with last year's decision, CRU/19/060, the CRU has engaged with GNI to further review the multipliers & seasonal factors. During these discussions both parties identified the need to build on the work done as part of last year's review. In proposing such a review, the CRU is cognisant of the potential for changes to multiplier & seasonal factors to have several wide-ranging redistributive effects. For example, reducing the seasonal profile range will result in seasonal network users being affected differently from those who use the network yearly.[16] In addition, a change to short-term multipliers would affect the residential customer category differently from the power generation category.[17]

A change to the multiplier & seasonal factor profile could also have effects on GNI and how it operates the network. For example, there could be changes to capacity booking profiles, revenue recovery and network demand patterns.[18] As part of any review it would also be prudent to consider the longer-term view, for example, how use of the gas network may change as Ireland moves to decarbonise the economy. This work could not be completed in time for the 2020/21 gas tariff setting process.

In addition, the increased uncertainty that the Covid-19 pandemic has brought must be factored into any decisions, and stability for consumers and industry may be beneficial at this time. The

[16] As those who use the system all year round will have a greater proportion of annual capacity bookings, which aren't directly affected by multipliers and seasonal factors.
[17] The non-daily metered sector, of which residential customers are the majority, are required to book annual capacity, while power generators are the biggest users of daily capacity. Reducing the cost of the daily capacity multiplier could therefore reduce the revenue recovered from daily products and lead to increases in the annual capacity tariff, affecting residential customers.
[18] See Appendix A for further discussion.

CRU has taken a number of measures to provide appropriate protection and reassurance for electricity and gas customers during the current period of uncertainty[19,20], and will continue to monitor developments and is committed to continuing to work with industry stakeholders and consumers during the Covid-19 pandemic.

As a result of the above, the CRU has decided that there will be no change to multipliers and seasonal factors for gas year 2020/21.

It is clear that changes to multiplier & seasonal factors have the potential to have wide reaching impacts. The CRU considers that, further work is required to assess these impacts and to ensure that the best approach is adopted. Not changing the multipliers and seasonal factors allows for additional analysis and provides stability and predictability of tariffs for the coming gas year. The CRU is proposing that a thorough assessment be completed in time for next year's Art. 28 consultation. The CRU aims to publish a consultation in early 2021 to ensure that any changes brought about by a CRU decision can be incorporated into the methodology time for gas year 2021/22. The CRU is taking this Art. 28 review opportunity to gather the views of stakeholders at this early stage, so that they can be incorporated into the review. To aid stakeholders, the CRU has provided some initial thoughts on the context of the review, the issues and presented analysis from GNI on current use of network.

2.3 Context of the review

With this review of multipliers and seasonal factors, the CRU is not only aiming to ensure compliance with EU regulations and network codes, the CRU is also aiming to ensure 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. In this section the CRU sets out its view of what should be considered in the review of multipliers and seasonal factors to ensure the best outcome for gas customers.

2.3.1 Criteria for tariffs and multipliers & seasonal factors

Regulation (EC) No 715/2009 sets out the European Union (EU) wide rules, which have the objectives of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks. In summary, Art. 13 of Regulation (EC) No 715/2009 requires that tariffs, or the methodologies used to calculate them shall:

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[19] https://www.cru.ie/cru-announces-covid-19-customer-protection-measures-to-assist-consumers/
[20] https://www.cru.ie/cru-extends-covid-19-customer-protection-measures-to-assist-consumers/

- be transparent
- take account the need for system integrity and its improvement
- reflect efficient costs
- include appropriate return on investment
- be applied in a non-discriminatory manner
- facilitate efficient gas trade and competition
- avoid cross-subsidies between network users
- provide incentives for investment and maintaining or creating interoperability for transmission networks

A crucial step in reaching these 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). Art. 7 of TAR NC sets out the criteria that the tariff methodology should meet. ACER's recent implementation monitoring report[12] states that the CRU's RPM has achieved compliance with the network code and as such meets the Art. 7 criteria. In the more specific context of multipliers and seasonal factors, which are applied after the RPM, Art. 28 of TAR NC states that the NRA shall take into account the views of respondents and the following aspects:

(a) for multipliers:

(i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;

(ii) the impact on the transmission services revenue and its recovery;

(iii) the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices;

(iv) situations of physical and contractual congestion;

(v) the impact on cross-border flows;

(b) for seasonal factors:

(i) the impact on facilitating the economic and efficient utilisation of the infrastructure;

(ii) the need to improve the cost-reflectivity of reserve prices.

It is the CRU's view that the review of multipliers and seasonal factors should be based on a consideration of the criteria highlighted in Art. 28, with any proposed amendments cross-checked against the overall requirements of Art. 13 of Regulation (EC) No 715/2009.

The CRU requests feedback from network users and end customers on what other criteria you consider essential as part of this review. When reviewing the multiplier & seasonal factor profile against these criteria, it is important to consider the context of the Irish gas sector and the role that it plays in the energy system as a whole. This is discussed further in the following section.

The CRU has also provided in Appendix A some initial considerations under the proposed criteria and presented these considerations in the context of the Irish gas sector where possible. The Appendix is aimed at providing stakeholders further insight as to how the CRU proposes to the review multipliers and seasonal factors under the proposed criteria, building on the work done as part of last year's review. Appendix A also contains additional data on use of the gas network and highlights some potential issues with the current multipliers and seasonal factors. The aim of this additional information is to stimulate discussion and provoke detailed responses to this call for evidence paper – it should not be taken as an indication of the outcome of the proposed review. The responses will assist the CRU in ensuring that it is aware of the important issues effecting network users and that these issues are fully considered and incorporated into the review where possible.

CRU Questions

1. Are there any other criteria that you consider essential as part of this review? Please provide a rationale for your answer.

2.3.2 The Irish gas network and market

Other than the minor adjustment to the multiplier & seasonal factor profile made as part of the 2019 review, there have been minimal changes to the profile in nearly 10 years. During that time there have been significant changes in the use and operation of the gas network. Such change will also continue into the future. As the profile attempts to incentivise efficient behaviour among network users, it is therefore important that the review considers how use of the network has changed and will change in the future so that the right signals can be sent / incentives applied. The following sub-sections highlight some key areas that the CRU believes should be considered in relation to changes in network use. The CRU requests feedback from network users and end customers on the issues you see as particularly important for consideration as part of this review.

2.3.2.1 Supporting renewables & changing patterns of network use

Electricity power generation accounts for a large percentage of overall gas demand (approx. 60% in 2018). Historically, gas fired power plants were typically baseload generation, resulting in relatively forecastable demand over the course of the year. However, gas plant are being viewed more and more as a flexible source of electricity generation. This is discussed further in Section A.2.1. This flexibility is one reason why gas is seen as a fuel that could support the transition to greater and greater levels of renewable generation – for example when the wind does not blow gas fired generation could provide the required backup. The current multipliers result in daily capacity being significantly more expensive to book than annual capacity. A review of multipliers should consider whether this differential is too large to further support the changing running order of gas fired generators. For example, it may be appropriate to consider whether the strength of the incentive to book longer-term products should be reduced. However, this needs to be considered against a range of other aspects and effects on things like tariff stability and revenue recovery, as highlighted is Section 2.3.1.

In terms of the interaction between the gas and electricity sectors, it also important to consider effects on the single electricity market (SEM). Firstly, there needs to be a consideration of the possible effects on the price of electricity, as gas often sets the price in the different market timeframes in the SEM. Secondly, there needs to be consideration that the SEM is an all-island market. As highlighted by the utility regulator (UR) in Northern Ireland in its Art. 26 consultation paper[21], it is beneficial to continue the alignment of multipliers and seasonal factors to ensure that there is no perverse pricing signal which affects the decisions of all-island electricity generators. As a result, the CRU will continue to engage and consult with UR on this issue, as it has done to date.

In terms of the changing role of natural gas, consideration must also be taken into account as to the potential to decarbonise natural gas. For example, GNI has published a vision paper for 2050 on how this might be achieved. In addition, the 2019 Climate Action plan published by the Department of Communications, Climate Action and Energy Efficiency, also seeks to establish the potential for decarbonising the gas network and setting its place in the energy transition. For example, there is an action to set a target for the level of energy to be supplied by biomethane injection in 2030, while a more limited role for domestic heating is envisaged. These actions also seek to consider an increase in gas to fuel transport – an area generally accepted to be harder to

[21] https://www.uregni.gov.uk/sites/uregni/files/consultations/2020-02-21%20-%20Consultation%20on%20seasonal%20multiplier%20factors%202020.pdf

decarbonise than others. The first steps have been taken in this regard with the first public Compressed natural gas fuelling station opened in Dublin Port.

In any review of multipliers and seasonal factors it is important to consider these changing uses for gas and ensure that they are not hampered and that the delivery of the climate action plan is supported. The review should therefore consider scenarios of changing demand and patterns in network user type, which will help to inform the types of incentives that should be sent via the multiplier & seasonal factor profile. It is important to note that the timelines for some of the technologies envisaged in the transition to a low carbon economy may take longer to deploy than others. The review should focus on nearer term technologies where there is greater certainty. As technologies develop, they can be considered in future changes. Less certain technologies can be kept under review and when they are more certain can be fed into analysis in future years. In addition, the CRU will continue to consider the effects of any forthcoming EU Directives, regulations and network codes on the Irish gas market, which includes multipliers and seasonal factors.

It is important to note that TAR NC also includes a possible future requirement for multipliers for daily and within-day products to be limited to 1.5 (currently, 3) of the annual product by 1 April 2023 in the case that ACER makes such a recommendation by 1 April 2021. This change would obviously have significant impacts. 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. It is important that the review of multipliers considers the potential for this change in the future. The CRU will continue to engage at a European level to ensure that maximum foresight of such a change is received.

It is proposed that the review would be led by GNI through the Code Modification Forum and that any recommendations from the review would be consulted upon publicly.

CRU Questions

2. Do you agree with the CRU's view of what the context of the review is? Please provide a rationale for your answer.

3. Are there any other aspects of the gas network or changes to the gas network that need to be considered as part of the review? Please provide a rationale for your answer.

4. Do you agree that the review should be led by GNI through the Code Modification Forum? Please provide a rationale for your answer.

2.4 Summary

Following last year's decision, CRU/19/060, the CRU has engaged with GNI to further review the multipliers and seasonal factors. The CRU has identified the benefit in further changes to the multiplier & seasonal factor profile so to account for changes in use of the gas network. These changes have the potential to have wide reaching impacts. The CRU considers that, further work is required to assess these impacts and to ensure that the best approach is adopted. This thorough review could not be completed in time for the 2020/21 gas tariff setting process. In addition, the increased uncertainty that the Covid-19 pandemic has brought must be factored into any decisions, and stability for consumers and industry may be beneficial. On balance and to avoid any unintended consequences of changing multipliers and seasonal factors at this time, the CRU has decided not to change the multipliers and seasonal factors now.

The CRU has decided that a thorough assessment be completed ahead of gas year 2021/22 and has identified proposed criteria and context for such a review. As highlighted in section 2.3.1, there are a number of criteria that need be considered when reviewing the multiplier & seasonal factor profile. The CRU has elaborated on these criteria and presented initial considerations in Appendix A, providing analysis of data from Ireland where possible. The CRU is taking this opportunity to gather the views of stakeholders at this early stage, so that they can be incorporated into the review, and has posed a number of questions in this regard.

The CRU would note that the CRU is not only requesting feedback on whether more assessment criteria should be adopted in its review. The CRU is also seeking submissions on how the use of the gas network is evolving. This would cover new uses for natural gas being transported by the gas network, such as its adoption for transportation fuel and the evolving role of gas fired generators. Supporting evidence as to how these uses are impacted by the current multipliers and seasonal factors would be beneficial in our analysis. In addition, feedback from other users of the gas network is equally important as changing multipliers may change the costs that they face. For example, gas shippers will have data as to how they purchase gas and the impact of multipliers and seasonal factors on that approach.

3 Level of discounts

3.1 LNG

TAR NC[22] allows for the adjustment (i.e. discount) of tariffs at entry points from LNG facilities. Unlike storage[23], TAR NC allows for, but does not require, the application of discounts to LNG 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 CRU/19/060 the CRU stated that it was 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 decided that proposed LNG projects can apply for a potential discount. The CRU set out non-binding criteria[24], 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).

The CRU continues to be of the view that this approach is appropriate. As the CRU has not yet set a discount, it cannot consult on the level of any LNG discount. The CRU will consult prior to setting an LNG discount in the future and will consult annually on the level of that discount as required by Art 28.

3.2 Interruptible discounts – Virtual Reverse Flow

3.2.1 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 Ireland via Moffat and

[22] Art. 9 – Adjustments of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilitates and infrastructure ending isolation.
[23] There are currently no storage facilities in operation in Ireland since the Kinsale gas fields began the blowdown of cushion gas. However, as stated in CRU/19/060, in the event that a storage facility began operation the CRU would apply at least a 50% discount in accordance with Art. 9. 1.
[24] See Section 3.8.3. of CRU/19/060 for further information.

into Ireland via Gormanston.[25] VRF is a day-ahead interruptible[26] product and the only interruptible product.

In accordance with the CRU's TAR NC decision paper, for gas year 2019/20 a new tariff was introduced for VRF, which replaced the previous registration fee approach. The calculation of the VRF tariffs at Moffat and Gormanston are now based on the TAR NC principles and requirements for standard interruptible capacity products.

Art. 16 of TAR NC specifies the calculation of reserve prices for standard interruptible capacity products by applying an adjustment to the reserve prices for the corresponding standard firm capacity products.

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

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

Where:

$Di_{ex\text{-}ante}$ is the level of the ex-ante (forecast) 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).

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

- The VRF tariffs are based on the Moffat exit point and Gormanston entry point reference prices, as calculated by the Matrix RPM.
- A Pro Factor of 8% is applied to the Moffat and Gormanston VRF products.
- A risk premium of 10% is applied to both the Moffat and Gormanston VRF products.

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[25] For example, if there is a total nomination of 100 units of gas for delivery from GB to Ireland and a gas shipper in Ireland wishes to virtually transport 10 units of gas from Ireland to GB, these 10 units are netted off the 100 units, resulting in the delivery of 90 units into the Irish gas network.
[26] 'Interruptible' capacity means gas transmission capacity that may be interrupted by the network operator. As this capacity is not guaranteed to be available it is often discounted. VRF is interruptible as flows from GB to Ireland are required to enable VRF as highlighted by the example in footnote 25.

- A market interaction factor of 30% applies to the Moffat VRF product only to bring the price below that of the equivalent forward flow tariff for reasons of cross-border trade.

These inputs result in an A-factor of 6 for Moffat VRF and an A-factor of 2.25 for the Gormanston VRF.

For the gas year 2019/20 this resulted in a Gormanston VRF reference price of €65/MWh and a Moffat VRF reference price of €250/MWh. By comparison the Gormanston exit reference price is €345/MWh and the Moffat Entry reference price is €301/MWh. Daily multipliers are not applied to the VRF product as it can only be booked on a daily basis (there is no annual VRF product). However, seasonal factors are applied to the VRF product. So, for example, the cost to book daily VRF capacity at Moffat in February is €57/MWh[27], while the cost in June is €1/MWh.

In accordance with Art.4 of TAR NC, commodity charges apply to use of the VRF product.

It should be noted that in moving from the previous registration fee to the above tariff saw a large increase in the cost of using VRF. The CRU was cognisant of this and took measures to ensure that the tariff reflected the nature of the VRF product while also ensuring that the VRF tariffs were lower than their forward flow equivalents to help avoid cross-border flow distortions. Setting the tariff in this way was a pragmatic approach based on the balance of information available and is aimed at ensuring utilisation of the VRF service. More about the challenges of setting an appropriate VRF tariff are now discussed.

3.2.2 Purpose of VRF and challenge in setting the tariff

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 notional location for trading 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.

As there are currently no flows through the Gormanston IP, VRF is not bookable at this IP, and has not been used. However, it is bookable and has been used at the Moffat IP, i.e. to export gas from the IBP to the NBP. The data shows that it has typically been used by shippers who are active at the Bellanaboy entry point (i.e. those shipping gas from the Corrib gas field).

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[27] (€250*2.28%)/2.79

As the IBP price should in theory be above the NBP price, one expects that the majority of gas from the Corrib gas field will be sold to Irish customers, with VRF enabling any surplus to demand at the IBP to be sold at the NBP.[28]

These trades at the IBP and the use of VRF must be assessed in the round with market dynamics that can at times be complex. Gas markets can often be simultaneously importing and exporting, as is currently the case in GB (exporting gas via interconnectors and importing gas via LNG tankers). There are also numerous confidential contracts between gas undertakings (e.g. producers, shippers, and suppliers), which the CRU does not have sight of. The numerous push and pull factors at play at any one time, make it difficult to have full sight of what is driving the price of gas and the use of VRF. This makes it challenging to set a “correct” economic value or A factor for the VRF product. This makes it very important to identify the correct data to focus on.

In setting the VRF tariffs, the CRU acknowledged these challenges and stated that it is difficult to predict all impacts of the new tariff. Given this, the CRU considered it important to assess, to the extent possible, the impacts of the new VRF tariff. The CRU stated that it would work with the Code Modification Forum to establish the factors that could be practically considered in this assessment; including the impact on the IBP.

At the recent Code Modification Forums, the CRU highlighted to industry that it was due to receive data related to VRF and that it would share this with industry as part of this year’s review. The CRU has now received this data from GNI and presents the analysis below. The goal of this analysis is to assess whether the new VRF tariff is appropriate, by examining the trends over time, comparing VRF use before and after the new tariff was introduced and the factors that might affect the use of VRF.

3.2.3 Analysis

3.2.3.1 Use of VRF

The dataset consists of daily information on the system average price (SAP) at the IBP and NBP, VRF use, and IBP to NBP transportation costs. As there are currently no flows through the Gormanston IP, VRF is not available, and therefore only data from the Moffat IP is analysed here. The main period of analysis ranges from 01 April 2019[29] to 20 February 2020[30]. The CRU has split the data into two periods and compared them. The first period, from 01 April to 30

[28] Please note that not all gas is sold at the IBP and shippers can trade gas bilaterally to or from other balancing points; sourcing gas for example across the interconnector from GB. So, this surplus only reflects that Corrib was trying to sell more gas at the IBP then purchasers were willing to buy.
[29] Date from which IBP activity set cashout prices.
[30] Most recent data cut-off point.

September 2019, is when the registration charge applied (i.e. the capacity and commodity tariffs were zero) and the second period, from 01 October to present, is when the new tariff has applied.

The first step was to look at the use of VRF over the two periods. This is presented in Table 2.

Table 2: Use of VRF

metric	April - September	October - Present
No. of days in period	183	140
VRF used (no. of days)	121	5
VRF used (% of days)	66.12%	3.57%

It is clear from the above table that the use of VRF has significantly decreased since the new tariff was introduced. This may indicate that the price of the new VRF tariff is at a level that makes the VRF product an unattractive option to shippers, i.e. it is not commercially viable to export gas from the IBP to the NBP. Recall that the A Factor aims to reflect the estimated economic value of the interruptible capacity product and that commercial considerations are part of the VRF tariff setting process.

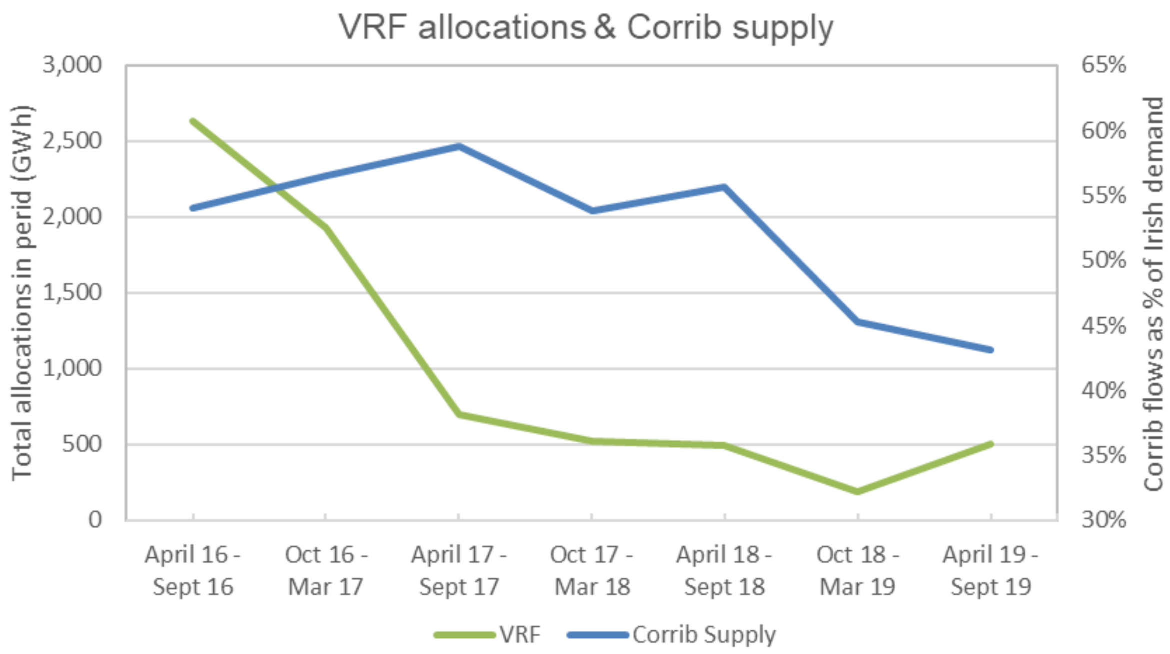
However, the solution to this issue may not be a simple reduction in the VRF tariff as there are likely a number of factors that shippers consider, when deciding to use or not use VRF. An example of such factors are as follows: the cost of transporting gas from Ireland to GB, the price of gas at the IBP and NBP, and the level of Corrib production versus domestic demand. There are also other factors at play, but these are the most obvious and likely to be the most significant. The CRU has further explored data related to these factors below.

3.2.3.2 Corrib production and Irish gas demand

Commercial gas flows at the Corrib entry point began in 2016 with maximum flows reached shortly thereafter, the field is now in decline. Therefore, the volume of gas shipped by individual shippers at the Bellanaboy entry point is in decline. In theory, as Corrib production reduces, the remaining portion (gas in excess of that needed by Irish customers supplied via Bellanaboy shippers) to be sold onto the NBP reduces and therefore the utilisation of VRF reduces.

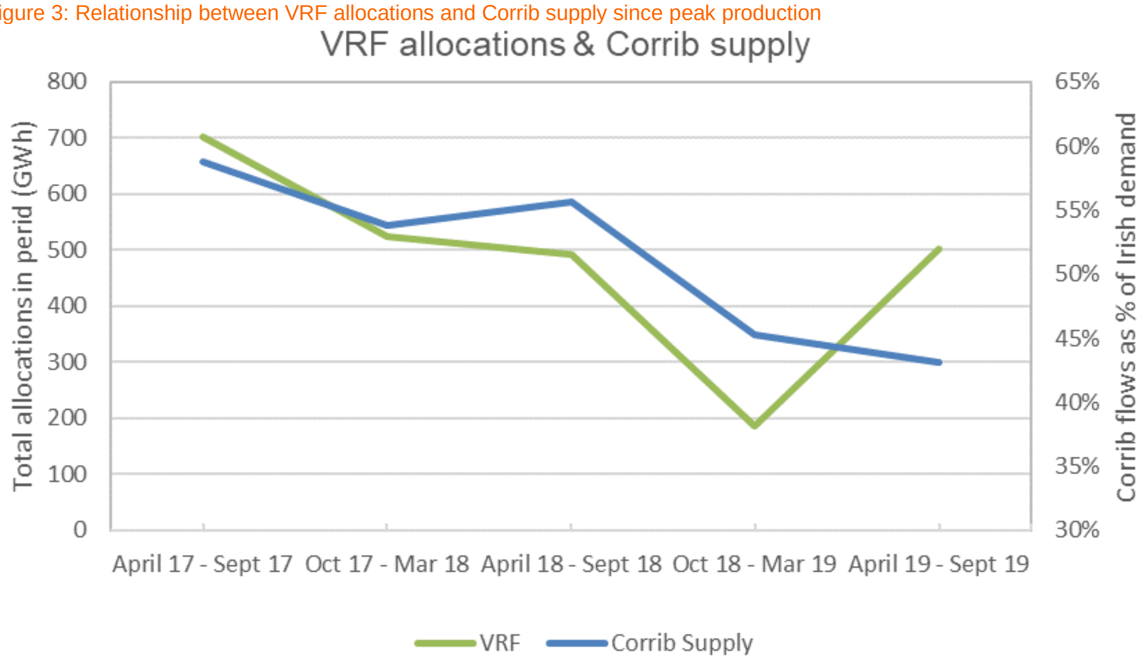
However, from the Figure 2 it is clear that it is not that straightforward. The green line represents the total VRF allocations and corresponds with the left vertical axis, while the blue line represents the Corrib supply as a percentage of Irish gas demand and is plotted against the right vertical axis. The expectation is that VRF use should be higher during periods where Corrib entry flows make up a higher proportion of total gas demand in Ireland (high Corrib production and low demand in Ireland could tend to signal that there is a greater likelihood of gas needing to be exported). Although it is clear from the following graph that in general the use of VRF has been highest during periods of higher Corrib production, it is not a consistent trend.

Figure 2: Relationship between VRF allocations and Corrib supply since production commenced



However, consider Figure 3 below where the first two periods (April 16 – Sept 16, Oct 16 – Mar 17) are removed, the expected trend is much clearer. These two periods were prior to Corrib reaching maximum production. It's possible that the initially high level of VRF use reflect reduced liquidity at the IBP and that it took time to develop the necessary commercial arrangements to supply Irish customers.

Figure 3: Relationship between VRF allocations and Corrib supply since peak production



However, in the most recent Summer period VRF use appears higher than expected. This could possibly be explained by the relationship between production and seasonal gas demand in Ireland. Irish demand is higher during the Oct – March periods, which when combined with a decrease in Corrib production, may have potentially resulted in less gas being available for export to GB and a significant reduction in the use of VRF in Oct 18 – Mar 19. The reduced Summer demand in the period April 19 – Sept 19, then led to a rebound in the use of VRF and a return to the levels seen in April 18 – Sept 18.

It could therefore be considered that the reduction of VRF use in the current 'October – present' period (as highlighted in Table 2) is not unexpected; however, it likely does not explain the very limited use of the product. To explore this further, the CRU has, in the following section, examined some indicators of the commercial viability of VRF.

3.2.3.3 IBP vs NBP spreads

As stated earlier, the IBP price is typically NBP plus transportation. However, it is difficult to know exactly what the actual average price at the IBP is on any given day as there are numerous trades between parties, which the CRU does not receive data on. The best estimate of the average price can be derived from the average price of visible trades, which are made on the IBP trading platform[31]. This electronic gas trading spot-market has been in place in Ireland since 2017. The average price is published every day and is known as the system average price (SAP). However, as mentioned earlier, the volume of gas traded on this platform is a small portion of the total gas demand in Ireland on a given day, and therefore there can be significant differences between the actual average wholesale gas price in Ireland and the IBP trading platform SAP.

Using the IBP trading platform SAP as a best estimate the CRU has examined whether there is a clear relationship between the use of VRF and the difference between the IBP and NBP SAPs. As stated, gas shippers will naturally try to sell their gas at the highest price and therefore, on days where the NBP SAP is at a premium to (greater than) the IBP SAP, it could be expected that there would be a higher use of the VRF product, as it allows access to the GB market.

In theory for it to make commercial sense to transport gas from Ireland to GB, the NBP premium has to be greater than the cost of transportation to GB, otherwise it would be more lucrative to sell the gas in Ireland. The relevant gas transportation charges in this case are the Moffat VRF

[31] https://www.marexspectron.com/

capacity and commodity tariff and the GB entry commodity tariff (the GB entry capacity tariff at Moffat is negligible).

Table 3 presents the days where it was theoretically profitable to export gas from the IBP to the NBP in a situation where the VRF tariffs were zero.[32] According to this analysis VRF was only profitable on 24 days over the period (183 days), i.e. 13% of the days. Recall that in the period April 19 – September 19 there was no tariff and therefore this assumption represents the reality at the time. Compare the number of days, i.e. 24, where it made theoretical sense to use VRF to Table 1 where the data shows that VRF was actually used on 121 (66%) of the days. By taking the likely assumption that shippers will generally only use VRF if it is profitable it can be deduced that this example does not accurately represent the actual commercial viability of VRF. This may indicate that shippers using VRF have been purchasing gas at a discount to the IBP SAP and/or selling it a premium to the NBP SAP . However, there are other factors that may have impacted on its use. These are discussed later.

In terms of potential discounts / premiums, visibility of these is limited. To give some indication of their potential scale, the CRU has applied a 5% discount to the IBP SAP and rerun the analysis. This 5% discount increases the number of profitable days in April to September period from 24 to 118. This is a much better fit for the 121 days in which VRF was used.

Table 3: Profitability of VRF with no tariff

metric	April 19 – September 19
Profitable w/ no tariff (no. of days)	24
Profitable w/ no tariff (%)	13.11%

In order to try to identify a trigger point in IBP & NBP spreads for the use of VRF the CRU further examined the 24 days identified above. In other words, to identify if VRF was always used if the NBP was at a certain premium above the IBP. The data indicates that there was actual VRF use 18 of those 24 days, i.e. 75% of the days, see Table 4. This is a slight increase on the 66% actual use of VRF over the entire period April 19 – September 19. Consider that these 24 days are the days when NBP SAP was at the largest premium to the IBP SAP, and therefore it would be expected that VRF would have been availed of on each or nearly all of these days. The fact that it wasn't utilised to a much higher degree on these days indicates that IBP and NBP spreads

[32] For example, on 20/09/19 the IBP SAP was 22.7p/therm and the NBP SAP was 25.3p/therm. The cost of transporting gas from the IBP to the NBP on that day is 1.7p/therm. Therefore, IBP + transportation was 24.4p/therm (rounded), which is 0.9p/therm less than the NBP SAP. In theory a shipper in Ireland could buy gas at the IBP SAP and sell it at the NBP for a profit.

are not the only driving factor behind the choice to use VRF.[33] In the next section the CRU considers another one of the factors potentially effecting the use of VRF in more detail – the cost of exporting gas from Ireland to GB

Table 4: Profitability of VRF compared with actual use of VRF.

metric	April - September
Profitable w/ no tariff & used (no. of days)	18
Profitable w/ no tariff & used (%)	75.00%

3.2.3.4 Cost of exporting gas from the IBP to the NBP

Table 1 highlighted that the use of VRF has effectively ceased since the new tariff was implemented. In order to understand the effect pre- and post- tariff consider the below example. Two dates are used in this example, the 1st of January 2019 and the 1st of July 2019. As stated earlier, seasonal factors now apply to the use of VRF, resulting in different costs across the year. Starting with an IBP SAP of 30p/therm, two export cost scenarios are examined. The first scenario is represented by the columns with 'No tariff' in the header. This scenario is essentially the previous registration fee regime, where the cost of getting gas to the NBP was just the UK entry commodity charge. The second scenario is represented by the columns with 'New tariff' in the header. This scenario illustrates the cost of exporting gas to the NBP under the new tariff methodology that has applied since the beginning of gas year 19/20.

Table 5: Cost of export

p/therm	01-Jan		01-Jul	
	No tariff	New tariff	No tariff	New tariff
IBP SAP	30	30	30	30
+				
RoI VRF exit capacity	0	1.66	0	0.04
+				
RoI VRF exit commodity	0	0.56	0	0.56
+				
UK entry commodity	1.67	1.67	1.67	1.67
=				
Total	31.67	33.89	31.67	32.27

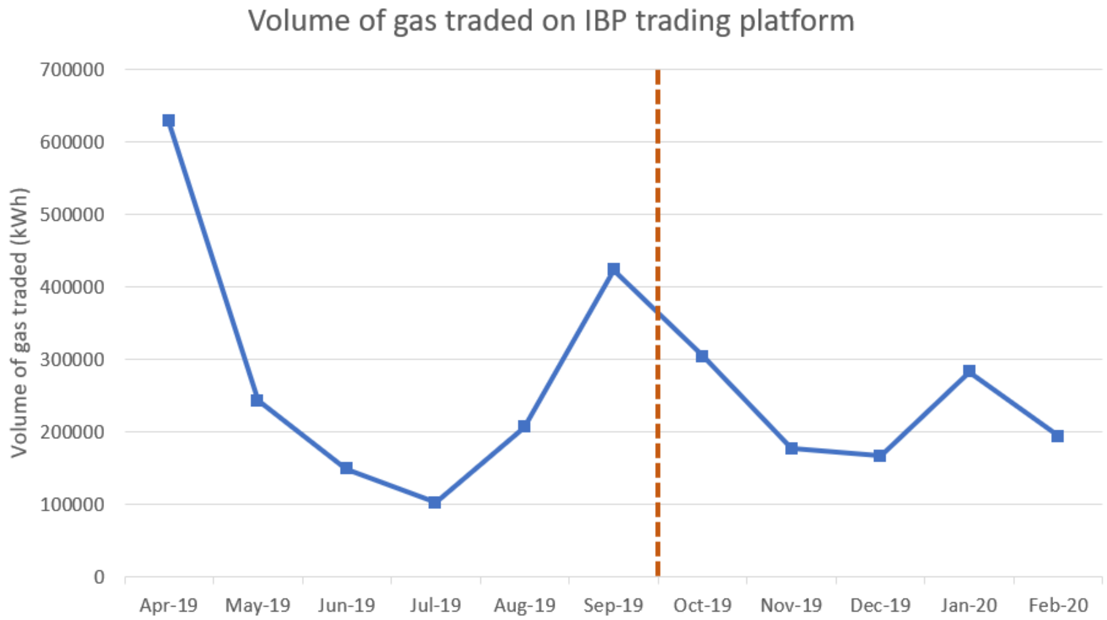
33 This is based on the assumption that the IBP SAP is an accurate representation of the actual IBP wholesale gas price on a given day.

From the table, assuming an IBP SAP of 30p/therm, the cost of exporting gas to GB has increased by approximately 7% in the January example and 2% in the July example. This highlights the significant effect that the seasonal multipliers have on the cost of exportation. The effect of significant increases in tariffs during the colder months, combined with the increased seasonal demand and reduced Corrib production could likely go some way to explaining the lack of use of VRF since October 2019.

3.2.3.5 Effects on trading platform

The CRU has also examined the available data to see if the new tariff has had an impact on liquidity at the IBP. In order to estimate liquidity at the IBP the CRU has examined the monthly volume of gas traded on the trading platform. This data is presented in Figure 4. The data is once again split into two periods to reflect the introduction of the new VRF tariff in October 2019. As highlighted by the figure there is no obvious impacts on liquidity due to the new tariff. It is important to highlight that the trading platform is a small portion of the total gas demand in Ireland on a given day and that measures of liquidity on the trading platform are the best available estimate of overall IBP liquidity. Regardless, identifying the effect of VRF use on IBP liquidity would be a very complex exercise as there are a lot of variables which can influence the number and volume of gas trades on the IBP trading platform, such as; the level of Corrib production against demand at that time, commercial strategies, wind and temperature.

Figure 4: Total monthly volume of gas traded on IBP trading platform



3.2.3.6 Considering an alteration to the methodology

As highlighted in previous sections, there are a number of factors which appear to affect the use of VRF. It appears from the data, that the cost of VRF under the new methodology, may have reduced the commercial viability of the product. As such, the CRU has considered whether it may be appropriate to adjust the A factor at this time, in order to make the product more viable for shippers.

However, the CRU is cognisant of the fact that the new tariffing arrangement has been in place for less than a year. As such, the CRU does not have a full suite of data to draw from when forming a view or decision on what may be an appropriate change. This is particularly important as we have yet to see the impact of the new VRF tariffs during the summer months. It is important to capture that impact as the seasonal factors applied to VRF see a significant reduction in its cost during the summer months; at a time when there is greater likelihood of export as discussed in section 3.2.3.2. This can be seen in Figure 5, which examines the cost of VRF over the course of the year (GNI VRF Moffat daily exit capacity tariff + GNI exit commodity tariff + National Grid entry commodity charge).

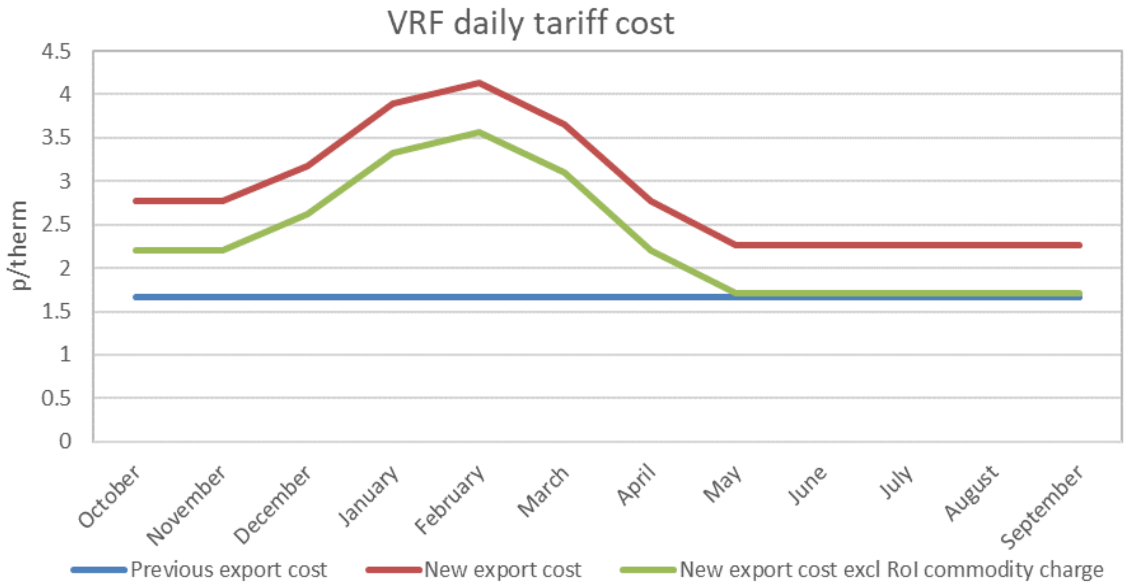
It is also important to consider the scope for the CRU to make future changes to the VRF tariff. If the CRU was to reduce the VRF capacity charge through an increase in the A factor, commodity charges would still apply. This is in accordance with Art. 4 of TAR NC which clearly states that the commodity charge shall be “the same at all entry points and the same at all exit points”. By way of understanding the effect of the commodity charge, the green line in Figure 5, represents the new export cost[34] (red line) minus the GNI exit commodity tariff. While the blue line represents the previous VRF arrangement’s export cost (i.e. National Grid entry commodity charge only). Note that in the months May – September the green line (new export cost minus commodity charge) is nearly equal to the blue line (previous arrangement). This highlights that the difference between the new export cost and the previous arrangement (blue line) in the months May – September is made up almost entirely of the commodity charge. As Art. 4 of TAR NC is quite clear that commodity charges must apply at all points, the CRU’s scope to reduce the cost any further in the months May – September is constrained.

The data that will be collected over the summer months will be particularly valuable as the CRU will then have been able to monitor the use of VRF under a wide range of different cost levels. In addition, a continued lack of us of VRF in these coming months may indicate that issues

[34] GNI VRF Moffat daily exit capacity tariff + GNI exit commodity tariff + National Grid entry commodity charge

regarding its use cannot be solved by changes to the VRF tariff given that the tariff may be as low as can possibly be achieved.

Figure 5: Cost of exporting gas from Ireland to GB via VRF



3.2.4 Summary

There has been very limited use of the VRF product since the new tariff came into effect in October 2019. In order to gain a greater understanding of the factors that might be affecting the use of VRF the CRU has examined IBP – NBP spreads, the cost of exporting gas to GB and the relationship between Corrib production and domestic demand. However, this data does not point to any definitive factor or trigger point, which determines the use of VRF. Its use is likely determined by a combination of the above factors and other commercial push and pull factors that the CRU does not have sight of and can be very complex in nature.

However, it appears likely that the limited use of VRF is in some part driven by the new tariffs. Due to the seasonal profile of the VRF capacity tariff the CRU will be able to monitor the use of VRF under a range of scenarios, ranging from its most expensive in February 2020 to its cheapest in May – September 2020. The CRU considers it important to gather this entire data set. By gathering this information, the CRU will be able to have visibility of the use of VRF under a range of different export costs, which may reveal some useful information on the economic value of the product, which is a key component in the VRF tariff formula.

By gathering a full set of data on the use of VRF over the course of the gas year 20/21 the CRU has the opportunity to gain a more comprehensive view of the drivers for VRF use. This data will be very valuable. It is on this basis that CRU is of the view that it would be too soon to make a decision to alter the new VRF tariffing arrangement, which has only been in place for approximately six months. In addition, the increased uncertainty that the Covid-19 pandemic has brought must be factored into any decisions, and stability for consumers and industry may be beneficial. On balance and to avoid any unintended, the CRU has decided not to change the VRF tariff at this time.

The CRU is keen to gather the views of industry on its analysis and would welcome insights (supported by data and analysis) into other factors, which significantly affect the use of VRF. In addition, network users might have useful data (e.g. bi-lateral contracts) on the commercial viability of VRF. As such, the CRU has posed a number of questions below. Responses to these questions will be assessed and incorporated into future analysis of the VRF tariff ahead of gas year 2021/22. The CRU aims to publish a consultation on any proposed changes to VRF tariffing in early 2021. This is to ensure that any changes can be incorporated into the methodology time for gas year 2021/22.

CRU Questions

5. Do you have any views on the CRU's analysis of VRF use? Please provide a rationale for your answer.
6. Do you have any information on the commercial viability of the VRF product, which may assist in setting the economic value of the tariff? Please provide quantitative data where possible.

4 Conclusion & next steps

The CRU has with this paper carried out its annual tariff network code Art. 28 review, in advance of gas year 2020/21.

Within Section 2 of this paper the CRU has provided its reasoning for not changing the multipliers and seasonal factors now. The CRU has proposed that a thorough assessment be completed ahead of gas year 2021/22 and identified the proposed criteria and context of this review. The CRU has also presented some initial considerations in Appendix A, which respondents should consider in their submissions.

Within section 3 of this paper the CRU provided an initial assessment of the impacts of the new VRF tariff. It examines the trends in use over time (comparing VRF use before and after the new tariff was introduced) and the factors that might affect the use of VRF. The CRU is seeking feedback, including supporting evidence, on this analysis to aid in the completing a review before tariff year 2021/22. The CRU aims to publish this consultation in early 2021 to ensure that any changes can be incorporated into the methodology time for gas year 2021/22.

To aid respondents, Table 6 provides a list of all questions posed throughout the paper.

4.1 Request for comment

Table 6: Request for comment

Topic	Query	Section
Multiplier & seasonal factor review	1. Are there any other criteria that you consider essential as part of this review? Please provide a rationale for your answer.	2.3.1
Multiplier & seasonal factor review	2. Do you agree with the CRU's view of what the context of the review is? Please provide a rationale for your answer.	2.3.2
Multiplier & seasonal factor review	3. Are there any other aspects of the gas network or changes to the gas network that need to be considered as part of the review? Please provide a rationale for your answer.	2.3.2
Multiplier & seasonal factor review	4. Do you agree that the review should be led by GNI through the Code Modification Forum? Please provide a rationale for your answer.	2.3.2
Virtual reverse flow	5. Do you have any views on the CRU's analysis of VRF use? Please provide a rationale for your answer.	3.2
Virtual reverse flow	6. Do you have any information on the commercial viability of the VRF product, which may assist in setting the economic value of the tariff? Please provide quantitative data where possible.	3.2

4.2 Next steps

The CRU will consider responses from stakeholders on the above questions. These responses will be assessed and incorporated in future analysis of these issues.

The following are the milestones that follow the publication of this call for evidence paper:

- CRU publication of tariffs for gas year 2020/21 – by 06 June 2020.
- Eight-week response period i.e. deadline for responses is close of business 14 July 2020.
- The CRU will review responses and engage with GNI. Further analysis will be carried out to examine issues highlighted in the responses. Proposals will be developed and analysed against tariff network code criteria (potentially including criteria suggested by respondents) – to end of 2020.
- CRU/ GNI engage with Code Modification Forum, providing updates and asking for initial feedback on proposals where required – Q4 2020.
- Article 28. consultation gas year 2021/22 published, setting out CRU/ GNI proposals – Early January 2021

CRU Disclosure Requirements

Unless marked confidential, all responses from companies or organisations may be fully published on the CRU's website. Respondents may request that their response is kept confidential.

The CRU shall respect this request, subject to any obligations to disclose information. Respondents who wish to have their responses remain confidential should clearly mark the document to that effect and include the reasons for confidentiality.

Responses from identifiable members of the public will be anonymised prior to publication on the CRU website unless the respondent explicitly requests their personal details to be published.

The CRU privacy notice sets out how we protect the privacy rights of individuals and can be found here.

A Appendix – Multipliers & Seasonal factors initial considerations

At the end of Section 2.3.1 the CRU set out the purpose of this Appendix. In summary, the purpose is to provide stakeholders further insight as to how the CRU proposes to carry out the multiplier and seasonal factor review and to provide additional information to stimulate discussion and provoke detailed responses to the questions posed. The initial considerations contained in this Appendix should not be taken as an indication of the outcome of the proposed review.

In order to further examine the multiplier and seasonal factor profile the CRU have separated these two components. This is because there are different criteria that need to be considered when setting each.

A.1 Multipliers

The current multipliers are shown in Table 7. They are now assessed against the following proposed criteria as proposed in section 2.3.1:

(i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;

(ii) the impact on the transmission services revenue and its recovery;

(iii) the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices;

(iv) situations of physical and contractual congestion;

(v) the impact on cross-border flows.

Table 7: Multipliers for capacity products

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

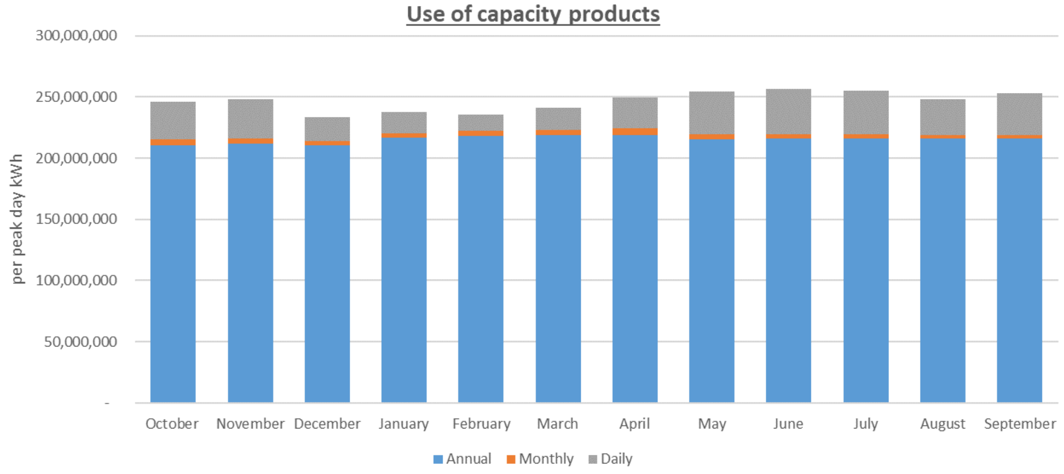
A.1.1 Initial analysis

The balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system

As highlighted earlier, multipliers are applied to the non-yearly costs in order to increase the relative attractiveness of the annual product versus the non-annual products. It is important to strike the correct balance in this regard; however, it presents a challenge. On the one hand if the price of non-annual products is at a too high level, it would reduce the ability of gas traders to participate in short-term trade; on the other hand, if it is too low, there would be reduced long-term bookings and therefore reduced long-term signals for investments. This is because gas network operators look at changes in forecasted capacity booking profiles for signals on changes in demand as they plan the future development of their networks. The presence of longer-term stable capacity bookings provides a better indication of future demand. The non-annual capacity multipliers should therefore be set at a level that encourages annual capacity booking, where the end user requires capacity on an annual basis.

In Figure 6 the CRU has presented data on the use of different capacity products. As expected, annual capacity makes up the majority of the overall capacity bookings.[35] The power sector makes up the vast majority of daily bookings. The daily booking trend is similar to the power sector demand trend highlighted in Figure 10.

Figure 6: Use of capacity products per peak day kWh (average of last four years)



[35] Quarterly is not included in the figure as there were no quarterly capacity bookings over the four-year period examined. However, there have been some quarterly capacity bookings since the CRU reduced the multiplier to 1.35. The CRU will continue to monitor its uptake.

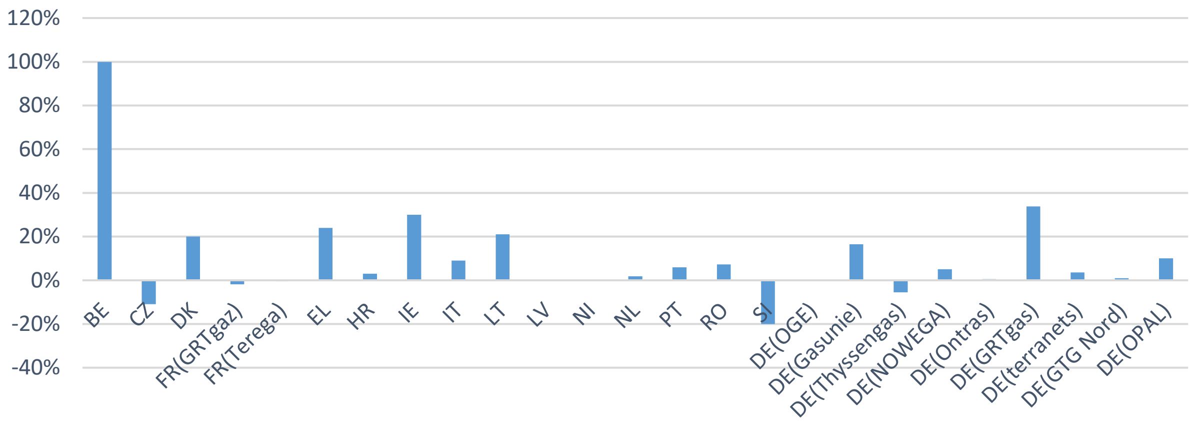
GNI has an optimisation software package that can aid in establishing what this annual booking requirement need is. This will be useful in estimating the lowest cost way in which shippers in each market segment could meet assumed booking requirements throughout the year given the different capacity product costs. This model will be a useful means of testing the effect of different multiplier levels against the intended outcome of efficient booking. Additional analysis and benchmarking with other jurisdictions could also be valuable in assessing the right balance and selection of multipliers.

The impact on the transmission services revenue and its recovery

As highlighted in section 1.2, tariffs are paid by network users so that GNI can recover its transmission services revenue. As multipliers effect the levels of the tariffs, they can also have an effect on the recovery of the transmission services revenue. For example, large daily multipliers can significantly increase the cost of daily capacity products. The cost differential created between the annual capacity product and the daily capacity product will send signals / incentives to network users, which can affect what capacity products they decide to purchase. This can have a significant effect on the recovery of transmission services revenue and the level of the annual tariffs. For example, if GNI's capacity forecasts indicated that demand for the more expensive shorter-term capacity products was going to increase, there would be a reduction in the annual capacity tariff to offset the additional revenue that would be recovered through the use of these more expensive products. Therefore, the larger non-annual multipliers can provide a benefit to users who do not avail of non-annual capacity products, through decreased annual tariffs.

However, in the event that a significant increase in daily capacity booking patterns was not foreseen, it would lead to significant over recoveries of revenue. This revenue would need to be returned to customers in future years through a decrease in the tariffs. Therefore, having large multipliers for the non-annual capacity products can also lead to increased revenue and tariff volatility. In recent years there have been significant over-recoveries of revenue, which has been driven in part by increased daily capacity bookings. The scale of these over-recoveries is highlighted in Figure 7, Ireland (IE) ranks as the third highest in this regard.

Figure 7: Over / under recoveries as a share of the allowed/target revenue, per TSO (source: ACER report -The internal gas market in Europe: The role of transmission tariffs – April 2020)



On the other hand, having very low non-annual multipliers reduces the incentive to book annual capacity. Annual capacity bookings are associated with more stable cost-recovery as capacity is booked for the entire year and paid for over the course of the entire year regardless of whether the network user flows gas or not. Having very low non-annual multipliers could lead to a sort of commoditisation of capacity bookings, whereby capacity is only booked on a daily basis for the amount of gas that needs to be flowed. Therefore, on a day where expected gas flows are not realised, capacity will not be booked and GNI recovers no revenue. This increased flexibility for network users can therefore lead to cost-recovery uncertainty.

The need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices

A key element of the CRU's 2019 review of the Matrix RPM centred around the cost-reflectively of reference prices in order to send appropriate signals to attract new investment where it can be shown to be efficient. While the continued application of the Matrix RPM ensures that the reference prices (i.e. annual capacity product prices) are cost-reflective, it is important to consider if the multipliers derive reserve prices for the non-annual products that are also cost reflective.

Consider the following table, which compares the non-annual product costs in the shoulder months (October, November, April) with the effective annual capacity cost on a shorter-term basis. The Moffat entry reference price (€301/MWh) is used in this example.

Table 8: Effect of shorter-term multipliers on non-yearly capacity costs[36]

Moffat quarterly		Moffat monthly		Moffat daily	
Effective cost of annual	Quarterly product	Effective cost of annual	Monthly product	Effective cost of annual	Daily product
€75/MWh	€116/MWh	€25/MWh	€38/MWh	€0.8/MWh	€1.9/MWh

While cross-subsidisation is a result of tariffs that are not fully cost-reflective, with the deviation from cost-reflectivity resulting in a user of the entry-exit system being allocated a tariff that differs from the costs they cause to the system. However, as complete cost-reflectivity is impossible to achieve there will always be some level of cross-subsidisation, it is therefore important to ensure that there is no undue cross-subsidisation. Cross-subsidies could arise between network users with rather flat transmission patterns and those with highly variable ones, since a very significant reduction in non-annual multipliers would result in a shift from long-term to short-term capacity bookings and an increase in tariffs for those with flat transmission patterns due to reduced revenue recovery.

It is also useful to think of cost-reflectivity in terms of the above example. TAR NC requires that the transmission services revenue is recovered through capacity-based charges. This is because capacity is one of the main network cost drivers along with pipeline distance. The presence of longer-term stable capacity bookings provides a better indication of future demand and may allow the TSO to reduce network costs through better planning. Therefore, there is an argument that shorter-term products should be priced at a premium as they could potentially increase network costs.

[36] As the multipliers are combined with the seasonal factors, the actual shorter-term multiplier can change on a month to month basis and day to day basis, i.e. it is only on an overall annual basis that the multipliers in Table 7 equate. To explain this further, consider that the actual October, November, and April daily capacity cost (€1.9/MWh) in the table above is only 2.3 times greater than the effective annual capacity cost on a daily basis (€0.8/MWh), however over the course of the year the average will be 2.79 as per Table 7.

Situations of physical and contractual congestion

Currently, there are no issues of contractual congestion on the Irish gas network and GNI does not foresee any issues arising in this regard in the future. However, potential physical constraints have been identified in local regions. GNI keeps the gas network under review for both contractual and physical congestion on an ongoing basis. In a situation where there is a significant amount of available capacity on the network the likelihood of future investment being triggered is significantly reduced, which may reduce the strength of some of the arguments for more expensive non-annual products.

The impact on cross-border flows

The Moffat interconnection point (IP), allows for gas flows into Ireland from GB. Domestic production is first in the merit order in terms of supply to Irish customers, with flows from GB via Moffat providing the marginal source. There is also an IP with the Northern Irish gas transmission system at Gormanston. The Gormanston IP is unidirectional, only allowing for gas flow from Ireland into the Northern Irish gas transmission system. However, no commercial gas currently flows in that direction; it is used for emergency support only. Therefore, gas flows into Ireland are a result of gas demand from Irish customers only, as there are no cross-system flows. Therefore, the CRU proposes to exclude this Art. 28 criteria from the future review. The CRU notes that the facilitation of short-term trade with GB (which doesn't necessitate cross border flows due to the Virtual Reverse Flow (see section 3)) would be considered as part of the criteria, which examines the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission.

A.2 Seasonal factors

Table 9 highlights the current seasonal factors applied for each month. The seasonal factor is multiplied by the relevant multiplier and the result is combined with the reference price to derive the tariff for each non-annual capacity product.

The seasonal factors are now assessed against the following proposed criteria as proposed in section 2.3.1:

(i) the impact on facilitating the economic and efficient utilisation of the infrastructure;

(ii) the need to improve the cost-reflectivity of reserve prices.

Table 9: Seasonal factors for capacity products

Month	Seasonal factors 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

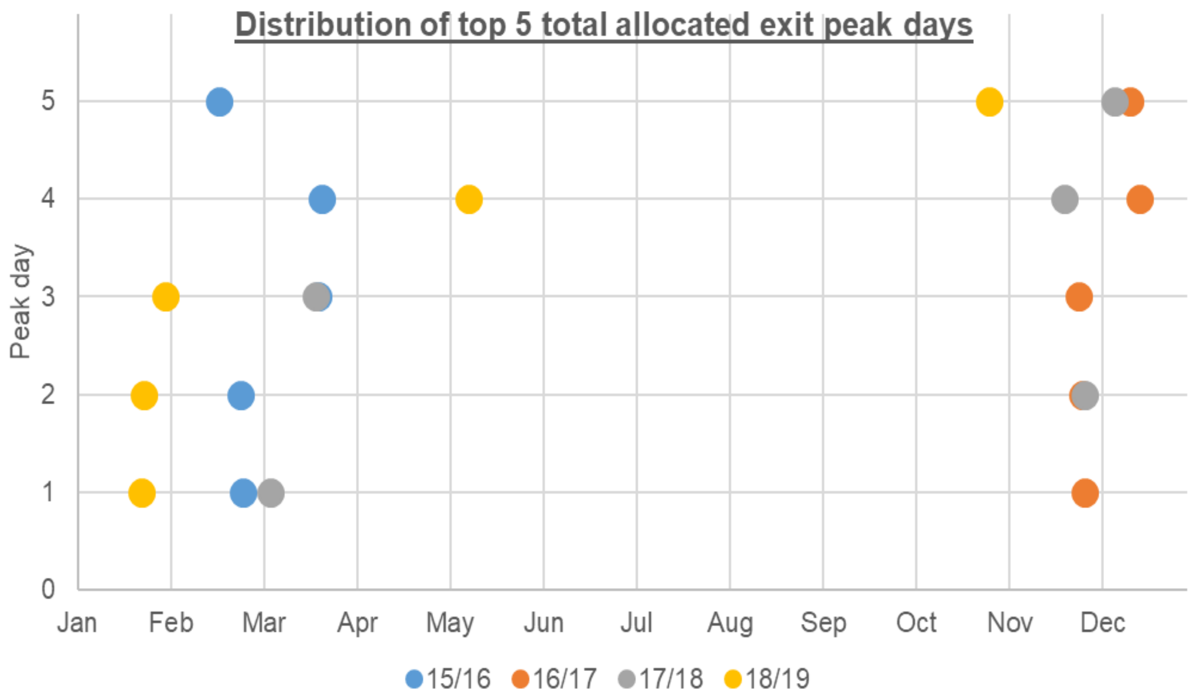
A.2.1 Initial analysis

The impact on facilitating the economic and efficient utilisation of the infrastructure

It is important that the gas network is used in an efficient way. The network is built to provide enough capacity for a 1 in 50 peak day[37]. As highlighted earlier, the current seasonal profile is derived from the probability of a peak day. Historically, these days have occurred in the Winter months. This has resulted in increased winter capacity costs and reduced summer capacity costs. This is further highlighted by Figure 8 which illustrates the date upon which each of the top five peak days occurred in the last four gas years. It is worth noting that in gas year 2018/19 the fourth highest peak day occurred on 10 May 2019.

[37] A 1-in-50 peak day is the requirement to fulfil gas demand during a 1-in-50 year severe weather scenario.

Figure 8: Occurrence of top five peak demand days at exit



As outlined above, peak days have tended to occur in Winter. This is due in part to the increased seasonal demand from the residential sector (i.e. home heating). However, this is beginning to change. The power sector now makes up close to 60% of gas demand and as highlighted in Figure 9, power demand peak days have a tendency to occur in Summer. This is because a key driver of demand in the power sector is the level of wind on the system. Flexible gas fired power generation can react to a reduction in wind and provide required backup generation. Such changes in the use of gas need to be considered in setting seasonal factors.

Figure 9: Occurrence of top five peak power demand days at exit

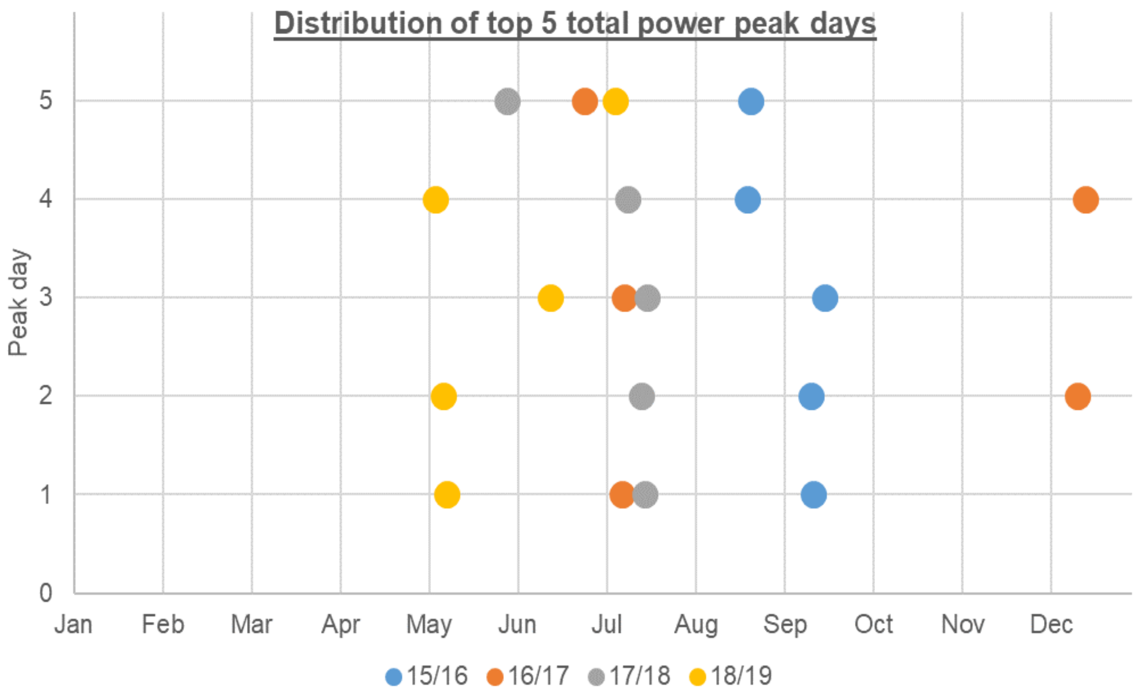
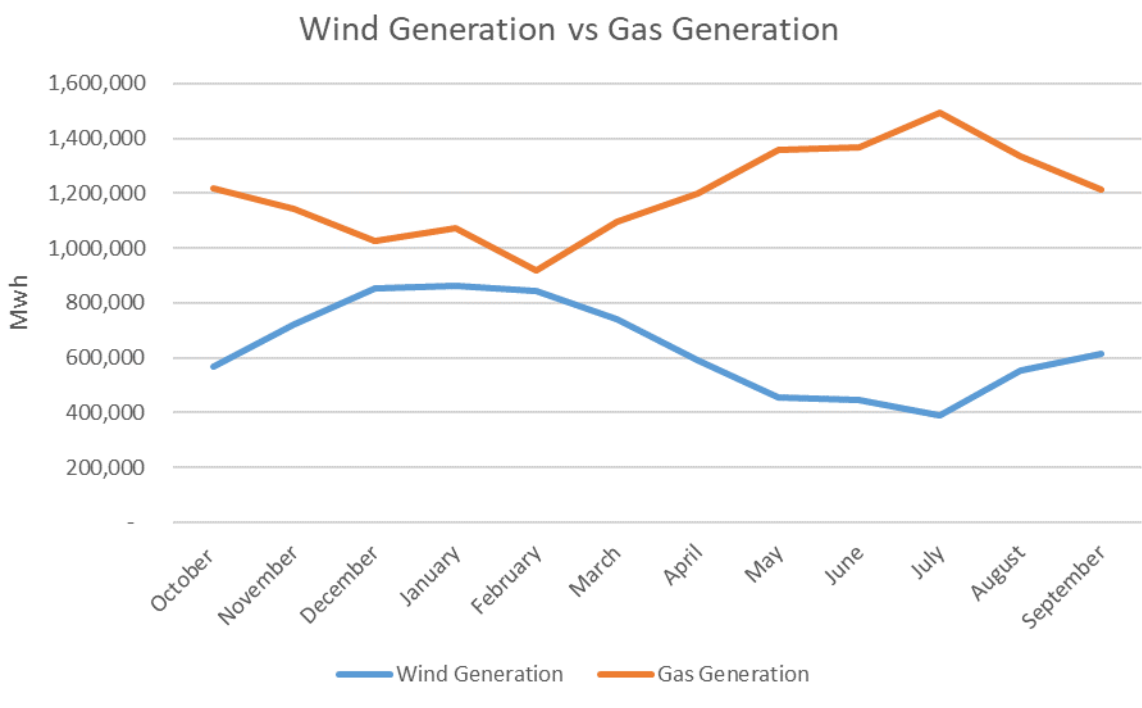


Figure 10: Average monthly wind and gas generation (last four years)

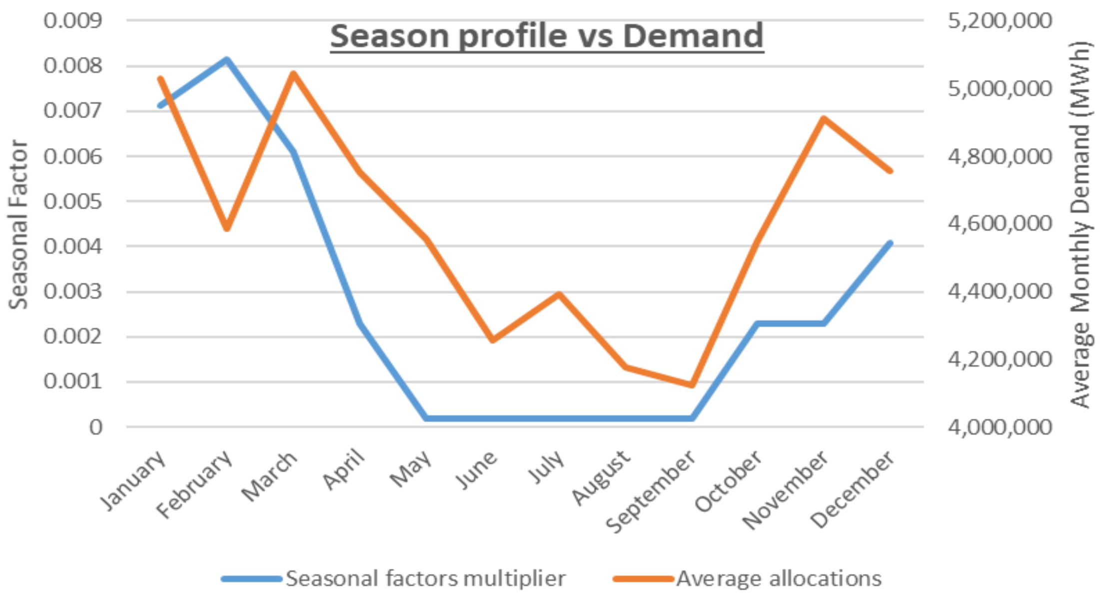


Currently however, the seasonal factor closely matches gas demand. This is shown in Figure 11, which compares the seasonal factors across the year to the average gas demand each month. This aligns well with the goal of seasonal factors is to increase utilisation of the network in the

Summer due to the presence of excess capacity on the network. In other words, the seasonal factors are reducing the cost of capacity during the Summer when demand is relatively low.

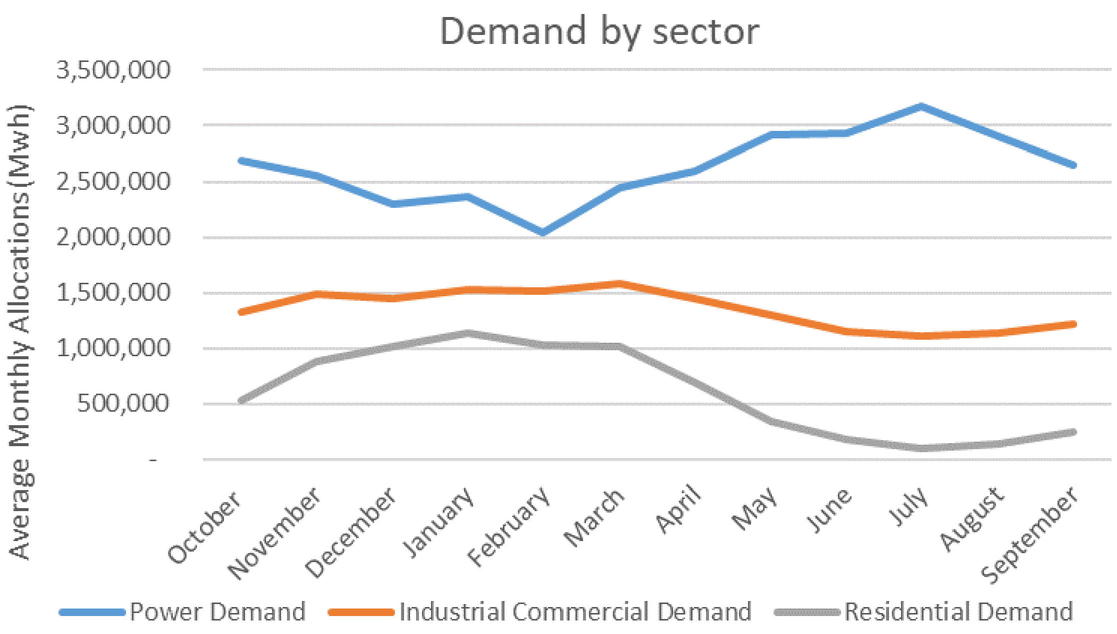
This incentive could encourage new seasonal demand (e.g. cement, tarmacadam industry) or indeed the movement where possible of existing demand from the peak Winter months to the Summer, thereby reducing the likelihood of additional network investment occurring.

Figure 11: Comparison of seasonal factors and gas demand



Creating incentives for new gas demand during times of relatively low system use, must be balanced with the need to avoid undue cross subsidisations. This needs to be considered. For example, it would seem undue if annual network users derived little benefit from Summer only users. However, if there is significant excess capacity in the Summer and system costs are driven by Winter demand, it may be appropriate for the Summer capacity cost to be reduced to reflect this. The challenge is deciding how large any reduction may be. In considering such, levels of seasonal use would need to be assessed, including what customer types are driving that demand. Some initial information on this is shown in Figure 12.

Figure 12: Comparison of network demand by sector (average monthly allocations last four years)



Additional analysis and benchmarking with other jurisdictions may also be valuable in assessing the right balance and selection of effective seasonal factors would be required.

The need to improve the cost-reflectivity of reserve prices

As highlighted earlier in the discussion of the cost-reflectivity of multipliers, the Matrix RPM ensures that the reference prices are cost-reflective. Therefore, in this regard, it is important to consider if the seasonal factors derive reserve prices for the non-yearly products that are also cost reflective. Consider the following example:

- In gas year 2019/20 the cost of annual entry capacity at Moffat is €301/MWh. This equates to €0.82/MWh on a daily basis.
- As per Table 1, the daily product is most expensive in February at 2.28% of the annual product. This means that the cost of booking a daily capacity product at Moffat in February is €6.87/MWh.
- As per Table 1, the daily product is cheap in May to September expensive at 0.05% of the annual product. This means that the cost of booking a daily capacity product at Moffat in May is €0.15/MWh.

This example illustrates the significant effect that the combined daily multiplier and seasonal factor profile can have on daily capacity costs. As highlighted earlier, the seasonal profile of the reserve prices for a capacity product at different times of year is 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. However, given that there is now greater possibility of peak days occurring in the summer months (as highlighted by Figure 9 & Figure 10 and associated discussion) the CRU questions whether the current profile retains the same level of cost-reflectivity.