Response

to

Utility Regulators Consultation

on

Short Term

Exit Capacity Products

9th June 2023

GMO Northern Ireland

Contents

Executive Summary
GMO NI is able to facilitate the provision of short term exit capacity products if UR decides they should be implemented. Our response is aimed at providing views, some analysis and information which is mainly concerned with the practical implications and to assist with consideration of the issues, but we are relatively neutral as to whether or not they should be introduced.

The main objective of the introduction of short term exit capacity products appears to be to improve the cost-competitiveness of the NI power generation sector. We are also aware of the anticipated benefits for the power generation market participants of greater alignment of exit product availability with the ROI.

On the other hand, short-term exit capacity products do not seem well suited to the distribution sector in NI. Their introduction here could be overly complex and it is not clear that it would bring material benefits to distribution network Shippers or the DNs.

In our response we explain further why, if short term products are to be introduced, we think a distinction in the exit capacity arrangements between power and distribution sectors would be appropriate. In any event, we would suggest the DNs should retain responsibility for booking a 1-in-20 capacity level for at least the non-daily metered load connected to their respective networks, consistent with the legislative position and the licence requirement for DNs to provide for 1-in-20 capacity levels. Whether or not there is an appetite for distribution Shippers to have access to short term exit products even for their non NDM portfolio is a matter for them to put a case forward for – it may be that some Shippers would welcome the chance to optimise their portfolio capacity bookings at entry and exit and could see cost savings and efficiencies or it may be that due to the size and make up of the NI market they would prefer to maintain something similar to the current arrangements which is less administrative heavy. If UR decides to maintain the current 1 in 20 regime, we suggest a small amendment to the ratchet mechanism for DN capacity bookings, for improved cost targeting which is discussed in further detail in the response.

We recognise that distinguishing between types of exit point in terms of exit product availability might raise a question of whether this would constitute undue discrimination and therefore any solution that is implemented would need to ensure that it is done so in a non discriminatory way. In our view, there could be a case put forward that keeping the 1 in 20 for distribution Shippers but allowing power Shippers to access short term products may be non discriminatory, providing there is sound rationale for doing so in favour of distribution Shippers. However, this may only become apparent after the outcome of this consultation and engagement process.
Given the possibility of material cross subsidy from the domestic to the power sector, it would seem to be important that the specific objectives for making any changes are clearly expressed. The parameters and details in the charging regime and reconciliation process can then be aligned to support those objectives. For

example, is the aim simply to address the potentially distorting effect of ratchet costs in the SEM, or to reduce the overall level of gas transportation costs faced by the power generation sector? Clearly the objectives of maintaining transporter revenue recovery and a reasonable level of tariff predictability will remain important and inevitably a balance would need to be struck between these objectives. GMO NI would be happy to support any further work to facilitate a clear definition of the objectives for any change.

If short term products were to be introduced for the power sector only the remaining practical concerns with the introduction of short term exit capacity products are:

a. the potential for redistribution of costs between the power generation and the distribution sector compared to the status quo, and
b. the potential for increased volatility in end-of-year reconciliation charges/payments and the consequential impacts on Transporters and Shippers.

In our view, there are a number of potential measures which could help to actively manage and/or alleviate these concerns:

- an even more rigorous process surrounding the provision and testing of annual forecast information
- the smoothing of seasonal multipliers, to reduce the financial impact of poor forecasting of short term products and hence reconciliation volatility, subject to consideration on the TSO within year revenue recovery profile
- potential adjustments to product-type multipliers, aiming to retain a share of cost broadly equivalent to that incurred today in the power generation sector and/or to otherwise balance the cost targeting between sectors, in line with whatever UR may select as the objective of making changes
- use of exit overrun charges where short term products are available, i.e. for the power generation sector only, to provide an incentive to book exit capacity
- potentially, the operation of a buffer account, to assist with managing volatility in reconciliation charges/payments and/or within year TSO revenue recovery, subject to clarification of the terms of its operation
- potentially, some mechanism to incentivise Shippers to forecast more accurately their bookings, subject to further development and consideration

Whilst all these measures require further definition and development to deliver on the potential timescales for introduction in October 2024, they all appear feasible, provided a prompt decision on implementation is made. It may be the case that some elements, for example the forecast accuracy incentive, could be developed as a "day 2" possibility, rather than as part of any initial implementation package.

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It is important to note that for implementation in October 2024 a licence modification would need to be in place before the tariffs are calculated by the middle of April 2024, and the scope of such implementation would need to be achievable for the code modification and IT systemisation for a go live of October 2024. Hence any licence modification for implementation should be developed as soon as possible.

We have organised our response into themes below and provide brief cross references to our answers to the Consultation Questions in Appendix 1.

1. Gas- Electricity Interactions and the SEM

The main objective of the introduction of short term exit capacity products appears to be to improve the cost-competitiveness of the NI power generation sector. We are aware of the anticipated benefits for power generation market participants of greater alignment of exit product availability with the ROI.

The consultation sets out that the impact on the SEM should be to improve market efficiency, although it may produce higher costs in certain trading periods, and that the overall impact on the NI participants in the market should be low given their smaller market share.

The actual cost impact will be a function of each individual company's SEM bidding strategy and we understand that there is a reasonable degree of commercial flexibility/choice around what costs may be bid into any particular market trading period.

The UR consultation paper does not provide detail on how implementing short term exit products and cost savings within the power sector directly benefits electricity consumers. We would also observe that the extent to which cost savings or increases for NI generators in the SEM translate into savings or increases for electricity consumers is a matter for the UR in its role in regulating the market participants and consumer tariffs in the electricity sector.

Having said that, the implementation of short term exit products would probably improve resilience, capability, and commercial competitiveness for NI electricity generation facilities. Although this is a general point which is hard to model quantitively, it should represent a benefit for NI electricity consumers. The extent to which cost increases for gas distribution network users (and how these are passed through to consumers) is similarly a matter for UR in its role regulating the gas market participants and tariffs.
The timing of consumer tariff setting/revision will be an especially relevant factor in considering the realistic extent of pass through of year end reconciliation costs or

rebates by Shippers to consumers, and the consequential impacts on shipper's profitability.

In summary GMO NI would welcome further detail on the rationale and objectives for implementation of short term exit products, along with how the cost savings/increases are born across both gas and electricity for clarification.

2. 1-in-20 Requirement

2.1 1-in-20 as a charging approach

The 1-in-20 level represents a very widely established measure of peak winter demand and therefore represents a minimum level of design capacity for pipelines. The use of 1-in-20 levels of capacity as a principle for the application of network charges at DN exit points is consistent with network operators recovering their (long run) costs, i.e. the cost of provision of all of the capacity, recognising the fact that pipelines may rarely be used at peak levels, but they must nevertheless be sized to meet the 1-in-20 peak winter demand.

It is important to note that the 1-in-20 requirement does not in itself assure the provision of gas supplies, only that the pipeline capacity is present and at exit only. In terms of the relationship between the 1 in 20 booking and security of supply, firstly there is no obligation at entry point for any distribution Shippers to hold capacity and so just because there is exit capacity does not necessarily mean that the distribution Shippers have entry capacity secured, and secondly it is the emergency arrangements that drive which customers are protected in a gas supply emergency. Currently for any load shedding required in an emergency, the power sector would come off first, followed by the industrial and commercial loads and finally the domestic sector. The capacity bookings are not considered in an emergency, with any cutbacks based purely on the throughput, and the load sectors on the emergency day.

It is also worth noting this 1 in 20 obligation is a licence condition and underpinned by legislation, and so any changes to this would not be straightforward from a commercial framework aspect, and also will be more complicated from a code and IT change aspect, increasing costs and timelines.

In summary as a charging approach GMO NI supports the 1 in 20 in terms of a charging principle for pipelines for DNO networks and it provides stability and certainty for TSO revenue, and for NI may represent the most efficient and suitable way of accommodating exit capacity bookings for Shippers, however there could be a case to be made for updating this to cover NDM portfolio only, which is outlined more in the next sections.

2.2 Responsibility for 1-in-20

In our view, the DNs remain the appropriate party to book and hold 1-in-20 transmission exit capacity for at least their domestic load, given their responsibilities to provide sufficient capacity on their own networks, and because of the administrative simplicity of the arrangement. In fact, we consider that it may add helpful clarity for all if it were explicit (in their Licences or the Code) that the DNs are not required or even permitted to book short term products.

Even though it might be theoretically possible to transfer the licence obligation to distribution Shippers to determine, book and hold their own individual 1-in-20 peak requirements for the whole of their supply point portfolios, for this to operate effectively the administrative processes would need to be very fast (and hence probably highly automated) to be effective when dealing with consumers changing suppliers. If exit capacity does not transfer promptly between Shippers in this situation, it would introduce contractual congestion as Shippers could effectively be 'double booking' for the same consumer. To avoid this, distribution exit capacity needs to effectively follow the consumer. If this capacity moving is based on a 1 in 20 obligation on the Shippers, there would be little room for actual optimisation of capacity bookings by Shippers in practice. In this instance the overall financial effect for Shippers would be to effectively commoditise the capacity, which is what the current arrangements already provide for.

We therefore consider the 1-in-20 requirement should remain the responsibility of the DNs and the principle of charging for this as a peak requirement should be retained. The main benefits of this would be to:

- maintain the current administrative simplicity of the arrangements
- maintain stability of a substantial proportion of revenue recovery for the Transporter, and hence
- reduce the risk of increased volatility of reconciliation payments for Shippers.

Cost allocation is discussed further in section 4.

2.3 Possible case for change for I&C

Since the legislative protection for a 1-in-20 winter demand is aimed at domestic consumers, a case could potentially be made to split I&C from domestic consumers and allow/require shipper booking of exit capacity for their I&C portfolio only, whilst the DNs continue to book 1-in-20 for the domestic load only.

For Shippers with I&C consumers this might meet an objective to reduce/optimise their individual capacity costs, or alternatively it could be a regulatory response to concerns over undue discrimination within the capacity regime. The extent to which short term products might offer a material benefit to distribution I&C Shippers would depend on the relevant load factors of their respective consumers and whether they are capable of commercial interruption, for example.

For such a solution this would be a shift away from current arrangements of the total capacity portfolio driving the 1 in 20 which is enshrined in licence and legislative obligations. In addition, as outlined previously any move away from the current 1 in 20 arrangement would require more complicated interfaces, contractual changes and ultimately increase IT costs and timelines.

One key question, subject to further considerations on the implementation would be do distribution Shippers wish to have short term products for their I&C portfolio or do they prefer the simplicity of the current 1 in 20 arrangement. If they feel that short term products could enable them to more efficiently and proactively manage their capacity portfolio and drive savings which would outweigh the increased administrative burden on the Shippers that comes with this arrangement, then this could be explored further however if there is no strong desire from that sector, and subject to non-discrimination, then it may be preferable to maintain the current 1 in 20 requirements for the entire DNO capacity portfolio.

GMO NI would be open to discussions on this matter if there is a strong appetite from industry and UR decides that this should be explored further.

3. Capacity Bookings, Ratchets and Overruns

3.1 Key Objectives and Properties

The ratchet mechanism is reflective of the current objective of the charging framework that all Shippers should book and hold, and therefore pay for, an exit capacity level equal to their peak annual requirement, to support the need for the Transporters to recover the total (peak capacity) cost of the pipelines.

Its current design means that Shippers who don't apply for their peak capacity at the start of the year defer paying for that peak until the time it occurs, and when it does occur they need to have the cashflow to be able to pay for that peak for the whole previous period of the gas year in one go, as well as needing to be able to maintain higher payments for each remaining month of the gas year. This within-year cashflow impact may be useful to some Shippers and a challenge for others. For a commercially rational shipper which can handle the cashflow issue, it makes sense to allow the ratchet to determine actual peak capacity rather than running the risk of over-booking however for others this may be an issue. In addition, we understand that when translating into the SEM bidding for the power sector, it can cause distortion for a plant in terms of dispatch priority due to all the costs of historic peak day capacity for the year being lumped into that one bid.

An overrun mechanism is an appropriate mechanism to accompany short term exit capacity products, to incentivise booking of capacity in the appropriate window/auction at the relevant capacity price. This incentive is important in the

regime since the booking of capacity drives revenue recovery by the Transporter. Failure to book capacity results in a 'punitive' price being attached to the capacity, but it will not constrain a shipper's ability to have gas transported (subject to there being sufficient capacity in the pipeline available) since gas flow nominations are not contingent on a shipper holding capacity. However, additional revenues from overrun charges do not mean greater revenue for the Transporter associated with that use of the pipeline. The additional overrun revenue paid to the Transporter during the gas year is currently shared amongst all Shippers at the year-end, in proportion to their relative total invoice value for the year. This means that essentially any Shippers who overrun on their capacity also benefit to a certain degree on the redistribution of the overrun revenue at year end.
This mechanism also means for the TSOs that it is extremely important the multipliers for any short term products are punitive enough to ensure Shippers book capacity to cover their loads and that revenue is collected during the year.

Whilst an overrun mechanism does encourage individual Shippers to book sufficient capacity for their gas flows, and hence improve the likelihood of regular revenue recovery by the Transporter, it does not provide any incentive for shipper forecast accuracy in relation to the forecasts submitted to the Transporter at the start of the gas year which is discussed further in section 5.4

3.2 Appropriate tools for the relevant products

If short term exit capacity products are to be introduced for power generation exit points, then GMO NI considers it would be appropriate to apply the overrun mechanism at those points in the same way that it applies for entry points, to provide the relevant incentive to actually book capacity, and for consistency with the objectives of introducing the products. Objectives are discussed further in section 4.

As noted previously, our view is that the 1-in-20 peak requirement for capacity booking should be maintained for the DNs, and probably for the whole of the capacity at DN Exit Points in the absence of further engagement with industry exploring the viability of moving to a 1 in 20 for the NDM sector only.

Where DNs continue to hold the 1-in-20 requirement, it makes sense that the ratchet mechanism should be maintained, again for consistency with the objectives of retaining the 1-in-20 capacity booking requirement, but we would propose one amendment to its design. This is discussed further below.

3.3 Prospective-only ratchet for DN Exit Points

On the basis of the DNs continuing to hold the 1-in-20 booking, including for I&C load, we suggest the ratchet for DN Exit Points should apply on a prospective-only basis, simply resulting in an automatic increase in the DNs capacity booking from the start of the month in which the unbooked peak occurs, rather than requiring an additional make-up payment for the peak capacity back to the start of the gas year. We do not consider this would mean the DNs would disregard their responsibilities to forecast and book accurately at the start of the year, although this could be further backed up in the DN's licence if it were a concern. It would simply provide revenue recovery protection if a mid-year booking for a growing downstream load was inadvertently missed. The reasoning for this is set out further below.

The NI transmission network is now fairly mature in most areas, but with some rapid growth in one or two locations. The existing rule, where the ratchet applies peak capacity charges back to the start of the gas year in the month, does not properly allow for new connections coming online mid-year and could lead to unintended redistributive effects amongst distribution Shippers.

For example, assume a new connection for a material load is due to commence operation mid-year and a new shipper will start supplying that load. The DN may be fully aware and have forecasted the load growth accurately, but in the event that a mid-year increase in exit capacity booking is missed, the DN would currently be required, through the application of the ratchet, to pay for the peak capacity of that load from the start of the year.

Hence, we suggest this small amendment to the ratchet for DN exit points to avoid this redistributive effect amongst distribution Shippers.

3.4 Aggregate DN Exit Point overruns only for I&C Short Term Products, if applicable

If it were decided to split the I&C load from domestic, and make short term products available to Shippers to book exit capacity for their I&C portfolios (whilst DNs retain the responsibility to book and hold the 1-in-20 level for domestic consumers) work would be needed to consider how the two envelopes of capacity would sit alongside each other and, in particular, how the ratchet and overrun charges would work to ensure fair treatment of exceeding booked capacity whilst also maintaining an appropriate incentive regime for correct capacity bookings.

3.5 Ratchet changes without short-term products

The consultation outlines that NI ratchet charges can produce discontinuities between NI and ROI bidding in the SEM and this leads to some inefficiency in the electricity market. We understand this to mean that when power generators bid in the SEM they may include the whole of a ratchet cost charged retrospectively back to the start of the year in one trading period.

The consultation seeks views on removing or amending the ratchet, without introducing short term exit capacity products, but it is not clear what the objective of this might be, given that it is not clear exactly which costs in the SEM are the target of concern. For example, is it the short-term step-up associated with ratchet

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costs which creates problems on the day with SEM bidding, or the overall level of cost which is the main concern?

Also, if UR was minded **not** to introduce short term products, for example over concerns about maintaining the current cost allocation between sectors, or from a preference to maintain the principles of the current 'peak annual' exit capacity charging model, then removing the ratchet may be counter to the overall intention to maintain the status quo.

However, if UR seeks simply to mitigate/reduce the impact of the NI ratchet, presumably to reduce the (short run) cost impact on power generation shipper associated with failing to have booked capacity in advance, then the ratchet could be applied in a prospective-only, penalty-free manner in the same way as outlined above in relation to the DN Exit Point ratchet, just increasing the booking for the remainder of the year to the actual peak level incurred (at the price of annual exit capacity). Such a change especially within the power sector exit points would also help reduce end of year volatility caused by over recoveries due to removing the collection of revenue right back to the start of the gas year, however is a step away from the principle of charging for the peak day capacity within the year.

GMO NI would welcome further work on how the ratchet could operate if UR decides not to implement short term exit products and would be available to support further analysis in this area.

3.6 Capacity as a tool for signalling infrastructure development needs

Bookings of capacity can sometimes be viewed as a means of signalling demand for investment in infrastructure, and auction processes are an appropriate method to allocate capacity where network demand for capacity is high and availability limited. In such circumstances there may be a strong correlation between longer annual bookings and signals for investment in the network. However, in NI currently there are no signals for investment coming from capacity bookings. This may change in the upcoming years at entry with future increased demand within NI however currently most capacity bookings are placed a year in advance, whether obliged to book a certain level or not. The current 1 in 20 booking carried out by DNOs is one such booking that mainly is placed for a year at a time in advance and so can only indicate what the level of demand is for the upcoming year and provides no longer term view and therefore signals for investment or otherwise. First come-first served processes are more appropriate where demand is stable or declining and/or where there is no likelihood of competition for capacity access and GMO NI would suggest that at exit points this would be the suitable process for any short term capacity booking implementation.

Further to this it follows that it is necessary to have a separate process for planning of the network. Currently the NI Gas Capacity Statement is such a vehicle and is carried out every year. However, this is developed by the gas TSOs based on

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information received from the various parties connected to the gas pipeline. There is no wider context to this such as consideration of what is happening in any other sectors that may also impact the gas network in the future. In addition there is no formal process that follows on from the gas capacity statement translating into network requirements and associated allowances to be provided for carrying out any network development that may be required.

Although not the subject of this consultation specifically, GMO NI would support improvement in the processes for network planning especially given the context of the energy transition and the need to work closely alongside other parties such as the electricity sector to allow for wider scenario planning, and defining a clearer process of how this translates into decision making by UR for the planning of the future gas and electricity networks.

4. Cost Allocation and Key Objectives for change in the Charging Framework

4.1 Charging Principles in the existing Framework

The existing NI legislative framework where:

- all network users are to pay the same unit prices for use of the network regardless of location (postalisation),
- TSOs need to recover all their allowed costs in the gas year (mutualisation), and
- DNs have responsibility for booking 1-in-20 peak capacity (security of supply legislation)

leads to a situation, as UR has indicated in its consultation paper, where providing short term products at the power station exit points would result in a level of redistribution of cost from power generator Shippers to distribution Shippers. Without any other mechanisms in force, short term products allow the user of those products to pay for their actual use of the pipeline, rather than their annual peak requirements.

UR has outlined possibilities for alleviating this cost shift such as smoothing of seasonal factors and introducing an ex ante entry-exit shift. Another option could also be to update the product multipliers so as to increase the price of the short term products which would obviously shift costs further onto those who utilise the products.

However there remains a question as to what the correct cost allocation between the two sectors is. It seems that the UR consultation, rightly so analyses the historic cost allocation between the sectors and outlines the options mentioned previously to ensure that any movement away from today's cost allocation split is softened for the distribution sector. This seems like a fair basis to carry out the implementation of short term exit products, however the question of what is a fair split between the two sectors is not explored in the consultation paper along with what is the overall objective of implementing short term exit products e.g. is it to overall reduce power sector costs?

It would be useful for UR to clarify if the only objective is to minimise the cost allocation shift over from the power sector to the distribution sector and to provide some analysis and commentary on the underlying fair proportionality between the sectors on paying for the network.

Relevant to the cost allocation split between the sectors it is also important to note that in the future there may be congestion at the Moffat Entry Point, leading to premiums being applied to auctions. In a congested world an individual Shippers booking strategy along with market dynamics will ultimately determine what costs they incur more so than peak day or pay for use drivers. In addition future patterns of use of the network will change due mainly to the energy transition which also could have an impact on cost allocation. Therefore in summary, any intervention in trying to accommodate cost allocation parity now may ultimately be trumped in the near future by these market/strategic driven booking arrangements and changes in the use of network driven mainly by the energy transition and so if cost allocation is to be maintained it will need to be a dynamic process for UR to regulate on an ongoing basis.

GMO NI would welcome further clarity from UR on objectives of cost allocation between the two sectors especially looking towards the future.

In the rest of this section, we give our views on options for maintaining cost allocation parity as current.

4.2 Ex Ante Entry-Exit Split

The consultation seeks views on whether an ex ante split of entry and exit charging, to move more cost allocation to entry, would assist in mitigating the impact of short term products being used (in the power generation sector). This would produce different underlying unit rates for capacity at different locations in the NI network and hence could be seen as being inconsistent with the postalisation legislation.[1] If that concern could be overcome, an ex ante entry-exit split could be viewed as a means to help mitigate the impact of large revenue recovery swings resulting from changes in exit capacity booking patterns, by simply reducing the overall cost to be recovered from exit points. On the other

[1] Potentially, this concern could be overcome on the basis of both entry points (and presumably any future new entry points) having the same rate as each other, and all exit points having the same rate (and noting that the postalisation legislation pre-dated the requirement to have an entry-exit capacity regime). Nonetheless, GMO NI would still consider the ex post approach preferable.

hand, it would transfer more cost to be recovered into the entry regime which already relies on short term products available to all entry Shippers, and where there is no peak booking requirement. Overall, this would tend to reduce the month-by-month stability of revenue recovery and increase the impact of poor forecasting of entry product use in the year end reconciliation.

We explain this view further below.

GMO NI reviewed the historic split between entry and exit capacity invoiced amounts as shown in chart 3 and it indicates that, over the last 5 years, on average just under 55% of capacity revenue was recovered from exit capacity invoices.

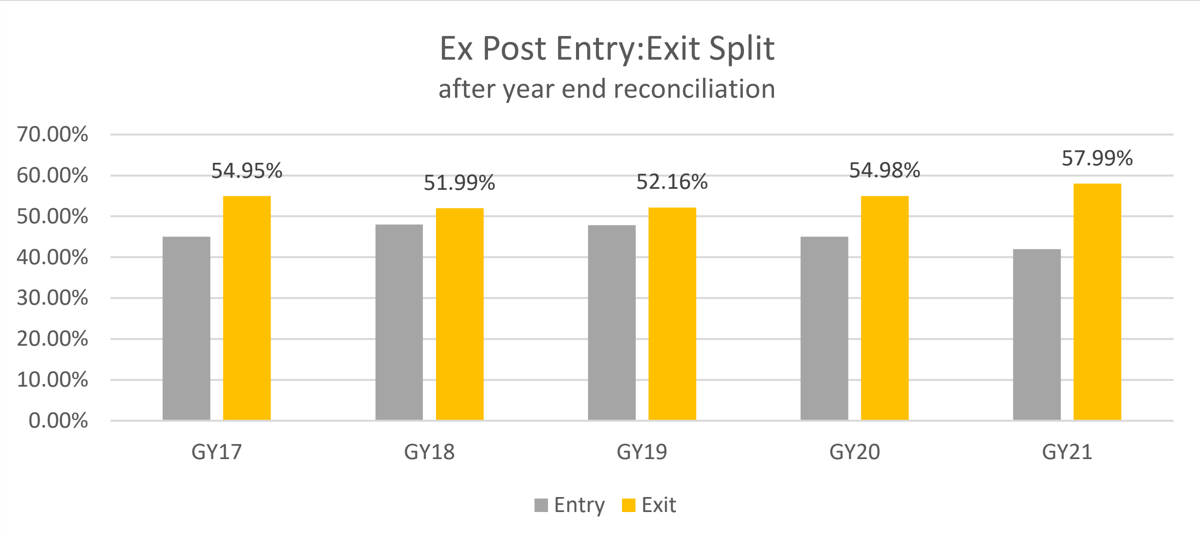

Chart 3

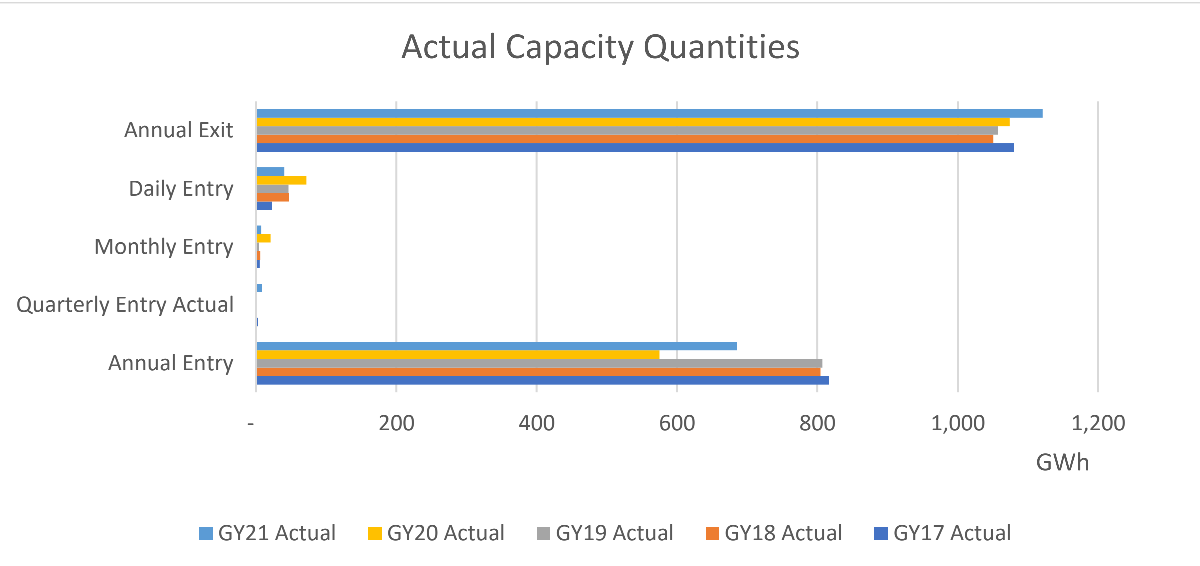

Chart 4

As shown in chart 4, historically the majority of entry capacity, and all exit capacity, has been booked as annual, meaning that the Transporters' revenue recovery is relatively stable through the year.

However, this is not a given and if the underlying price of entry capacity were increased (by setting an ex ante entry-exit split weighted towards entry), this would increase costs to be recovered from entry and hence the price of entry capacity, and could therefore encourage Shippers to further optimise their bookings to more closely match their gas flows. More use of short term entry products could therefore lead to more month-by-month revenue variability for the Transporter.

Furthermore it is generally the case that charges for network access need to be set in a pragmatic way so as to meet the relevant regulatory objectives for the network at the time; for example, to drive revenue recovery to cover investment costs (e.g. in the early stages of a new network), to encourage optimum use of a mature network or, where competition for capacity or choices for network investment locations exist, to provide signals for investment. If these latter two considerations were objectives for a regulatory framework, then a Capacity Weighted Distance (CWD) model of charging would be relevant and potentially useful. However, this is not the case in NI where we have a very simple and mostly mature transmission network. Nor would a CWD model be permissible under the postalisation legislation. The current objectives of the charging regime remain consistent with the intention of the postalisation legislation, which was primarily concerned with simple, stable and fair (peak) cost recovery.

For the reasons provided, GMO NIs view would be to retain the current ex post approach to the entry exit split.

4.3. Seasonal Factors and Product Multipliers – Tools for Sector Cost Allocation

The consultation seeks views on smoothing of the Seasonal Factors to assist in mitigating volatility in the reconciliation process and URs Seasonal Factors Consultation proposes this could apply from the start of GY24.

We note that smoothing the Seasonal Factors might constitute a move away from URs historic policy of aligning with the ROI policy on these factors. If the aim of introducing short term exit capacity products is to try and align with the electricity sector better overall, then such a policy shift may be justified.

In GMO NIs view, it is clear that flattening the seasonal factors would reduce the impact of shipper mis-forecasting entry and exit capacity bookings as between months or quarters with different prices and, provided forecasts are otherwise broadly accurate in total, hence contribute to minimising the scale of year-end reconciliation charges.

The individual Product Multipliers (as distinct from the Seasonal Factors) also offer an opportunity to adjust the targeting of cost recovery between sectors. Assuming no short term products are required/permitted for DN exit points, short term Product Multipliers would only be relevant to the power station exit points and could potentially also be set differently as between entry and exit. Adjusting the (exit) Product Multipliers would therefore provide a means of targeting a specific level of cost to be recovered from short term exit products at power station exit points.

GMO NI has also responded to URs consultation on seasonal multipliers and would be pleased to assist with further modelling and analysis on product multipliers should this be required by UR.

5. Reconciliation Volatility and Forecasting Accuracy

5.1 Drivers of Volatility

Shipper forecast accuracy at the start of the year is the key driver of volatility in the year-end reconciliation payment and the difference between forecast and actual costs of the Transporters for the gas year.

Volatility would increase if the annual forecast accuracy of any party were to worsen. Implementing short term products at exit further increases the risk of forecasting accuracy

For context, the NI Shippers as a whole have a reasonable track record for forecasting short term product use at entry as illustrated below.

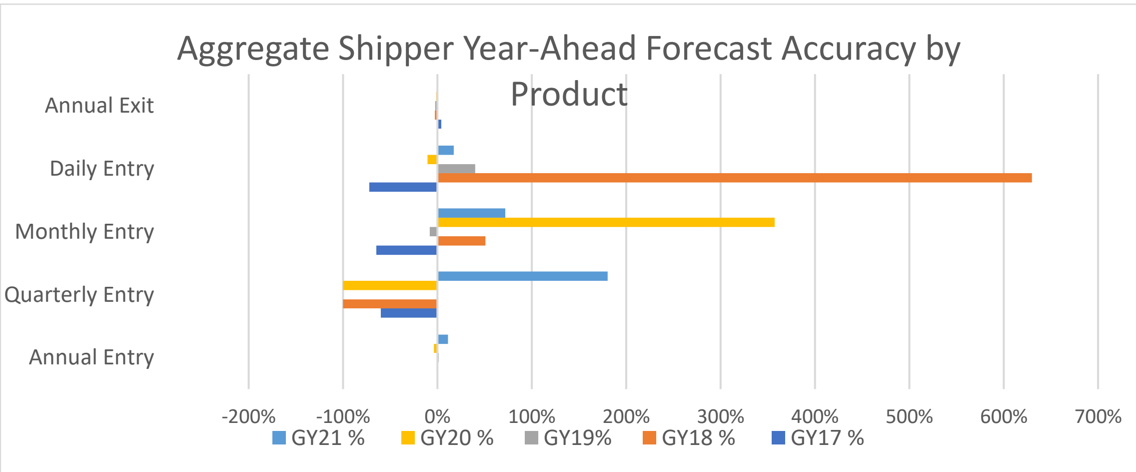

Chart 7

Chart 7 suggests that daily capacity can be the most challenging to forecast accurately but monthly and quarterly have also had a variable track record.

It should be noted that no quarterly capacity was forecast by Shippers for GY22 or GY23, or booked for GY22 to date. Whether or not is has value as a short term product for exit could be debated. Whether it should be included in any package for exit capacity products might be more a question for Shippers to answer and UR may get some relevant feedback on the inclusion of such a product.

5.2 Impacts of Volatility

Large reconciliation payments may present cashflow challenges for Shippers, as they are not necessarily aligned to the timing of resetting of consumer tariffs and, although useful the quarterly information published by GMO NI due to its nature is purely indicative and subject to variability.

Annual capacity products lend themselves to the stability of Transporters revenue recovery and greater use of short term products will inevitably lead to volatility in that process. As well as enabling the cost recovery for the provision of peak pipeline capacity for domestic consumers, the booking of 1-in-20 capacity by the DNs therefore also serves to maintain a material degree of revenue stability and hence tariff predictability, so benefitting both the Transporters, distribution operators and Shippers as a whole.

With the implementation of short term exit products there comes the increased risk of volatility and therefore it may be useful for both TSOs within year regarding collection of revenue (and especially for MEL when considering bond repayments) and also at the year end for Shippers in relation to large bullet payments to look at means for both incentivising the forecasts to be more accurate, and for smoothing any peaky cashflow requirements by the TSOs and/or Shippers.

5.3 Expectations of Future Forecast Accuracy Performance

Given the complexity of cost recovery through the electricity trading arrangements, power generation operators must produce their own detailed business forecasts at the start of the year and update them during the year, and there is no reason why this process should not readily extend to short term gas exit capacity products. Responsibilities for the provision of accurate information to the Transporter are already included in shipper's licences, but the strength and enforcement provisions on these could be further considered. For example, GMO NI could be empowered to make more detailed engagements with the power generation Shippers and SONI with accompanying requirements on those parties to provide certain information all with a view to a deeper dive on assumptions used in the forecast submissions.

Further to this, power station dispatch patterns must be the biggest potential uncertainty and is to some extent unknowable, especially as generation patterns change and increasing flexibility between wind and gas generation is called for. It therefore may seem potentially unreasonable to create really material incentives which would penalise the power station operators for this uncertainty. However accurate forecasting remains very important if large year end swings are to be avoided, and there may be merit in making that more explicit within the regime. GMO NI has therefore outlined some incentive approaches below.

It is important to note these are initial suggestions and GMO NI would suggest that time would be taken to design and deliver such an incentive scheme with further engagement with Shippers.

5.4 Possible forms of Incentives for Forecast Accuracy

Shippers are asked to forecast their entry and exit capacity bookings and their commodity (gas flows) at the start of the gas year. In the first instance, it would be possible to analyse individual shipper annual forecasting performance for scrutiny by UR and/or even publication. A more active industry process of routinely updating forecasts at intervals through the year, along with increased public transparency of (which could either be anonymised or alternatively adopt a name and shame principle) individual performances may serve to encourage even greater focus, before considering financial measures.

Creating an incentive for forecast accuracy for Shippers within the intentions of the postalised regime is a challenge. For example, the respective shipper contributions to year end reconciliation charges, or benefits from a reconciliation pay out, could be scaled based on some assessment of annual forecast accuracy performance, such that 'poor' forecasters receive less benefit from or contribute more to the reconciliation than 'good' forecasters. But because it is the underlying rates for capacity and commodity which are effectively corrected in the reconciliation process, this would mean different 'net' unit rates for individual Shippers and therefore be at odds with the postalised tariff regime.

However as noted in section 3.1, Overrun revenues do not currently flow into the 'PoT' reconciliation, which means they do not contribute to ARR recovery, and instead are redistributed to all Shippers in proportion to their total annual invoice values. Whilst Overruns are not necessarily a direct result of poor annual forecasting, they do produce a small pot of funds and arguably the current redistribution of them back to all Shippers, including those who incurred them, could be improved upon.

Hence one possibility for creating a forecast accuracy incentive would be to divert the Overrun revenues (for both entry and exit products) into a forecast accuracy scheme pot which, broadly, would be allocated at the year end to 'good forecasters' in higher proportions than the 'less good forecasters'. It would be logical to exclude any party incurring overruns from receiving any benefit from overruns, or at least to reduce their share to reflect the scale of their contribution to the overrun pot.

It is worth noting however, that due to the size of the capacity overrun pot this may not create much of an incentive as such currently.

We would also observe that within the mutualisation arrangements, it is not possible for the relevant transporters to pick up costs or benefits arising from an incentive scheme of any kind. Robust licence arrangements are already in place to govern the process of regulatory approval of the FRR and the ARR.

GMO NI would welcome the opportunity to engage further with UR and industry to design and develop options for a possible incentive scheme on forecasting accuracy.

5.5 Other Possible Mitigations for Reconciliation Volatility: Buffer Account

GMO NI is aware that MEL has had initial engagement with UR on a possible buffer account for either within year TSO recovery requirements and/or for end of year smoothing of large reconciliation amounts for Shippers. Although mainly a matter for MEL to develop further principles on the operation of such an account, in principle GMO NI supports any element that aims to lessen the scale of any revenue shortfalls or payment obligations by TSOs and Shippers due to the differences caused by forecasts versus actuals, and if required is available to help feed into its design, development and implementation.

6. Capacity Transfers

At power station exit points, there may be benefits in allowing exit capacity transfers between Shippers, if there is more than one shipper supplying that point. Since this is a possibility, facilitating exit capacity transfers at these points could be sensible to avoid contractual congestion.

In line with its aforementioned views on the arrangements for distribution exit capacity, GMO NIs view is that transfers of exit capacity between Shippers at the same distribution exit point are not required in the NI regime that is unless short term products become available at the distribution exit points. Such transfers would need to be considered from an automation aspect and feed into the overall IT scoping and costing as to whether it would be manual, semi manual or required to be fully automatic.

GMO NIs view on transfers of exit capacity between exit points is that this would not necessarily fall under the scope of short term product implementation as it is a wider and more complicated issue, which could be looked at if there was an appetite at a later date.

7. Implementation

7.1 IT Requirements and Costs

GMO NIs high level analysis would suggest that an introduction of short term exit capacity products to Delphi would take 9-12 months to complete from initial scope/design through to system implementation however this is based on the suggested scope as outlined in the UR consultation paper i.e. that short term exit products are for the power sector only and the current DNO bookings remain as is currently. If PRISMA were to be selected as the user interface, there would still be substantial integration work to be completed in Delphi. Until such time as a clear scope of works is defined it will not be possible to give a more accurate estimate.

GMO NI considers that the work to develop and update the PSA model is less significant in terms of time, as the model does already contain some functionality which would assist. GMO NI has been looking at options for updating the current PSA model due to certain functionality not being current or incorrect and also with a view to the future. There will be costs and timelines associated with a new/updated model with possibly new functionality being required depending on a finalised scope of any implementation of short term exit products. A clear scope for the package of changes required is needed before a complete "in the round view" on what updates to the model should be made. In particular, clear decisions on whether or not a buffer account was to be used, the rules for its use, and whether or not changes are to be made to the reconciliation process would be needed.

Short Term Exit Product implementation was identified as a Tier 1 project under the GT22 price control submission by GMO NI, with the allowances gained in principle for such a project. Tier 1 projects under the submission had specifically requested allowances as they were more likely go ahead during the GT22 price control period, albeit with costs based on various assumptions. The cost submitted was based on CGIs experience of previous implementation projects along with an assumed scope in July 2021. As the scope of the project is still not fully known it will only be after this consultation, plus any post engagement leading to a UR licence modification process, that the scope can be finalised. At that point it will be possible to crystalise the full and final costings for any contractual or IT (Delphi & PSA Model) costings.

GMO NI will also need to assess the costs alongside other potential project costs currently being considered and will highlight any areas of concern to UR.

7.2 Licence/Code Modifications

The Utility Regulator has noted in the consultation paper that a decision of whether to introduce short term products and smoothing of seasonal multipliers will be decided on in September 23 and licence modifications by December 23. It is important to note the following and that date deadlines, noted in consultation paper, will need to be met taking in consideration tariff licence requirements:

Licence Modifications

Consultation: At least 28 days

UR Decision: No time stipulated

Implementation: At least 56 days from the publication of the decision to proceed with the making of modification

Code Modifications

Preparing Initial Modification Report: No time stipulated unless a Shipper / UR proposes it then 25 business days are needed

Consultation: 20 business days

Preparing Final Modification Report: 20 business days

UR Decision: No time stipulated

Implementation: As per UR decision however normally an implementation date is proposed in the FMR

In addition to the code and licence changes there may be associated contractual changes depending on the scope for the final solution eg, information sharing agreement between the TSOs and the DNOs.

Appendix 1 – Cross References for Answers to Consultation Questions

Merits of introducing short term exist capacity products.

8.1 Do Respondents consider that short term exit capacity products should be introduced? Please explain the reasons for your view and provide supporting evidence.

Please see the executive summary

8.2 We are interested in views on which exit capacity products should be available at exit. Do you agree that these options should mirror those currently available at transmission entry points with the exception of quarterly products? Please explain the reasons for your view

8.3 Are quarterly products required at the exit point? If so, why?

Please see section 5.1

8.4 Are there any further risks or consequences that may arise as a result of introducing short term exit capacity products that we should consider? Please identify whether these consequences impact the gas or electricity market/consumers and provide supporting evidence.

Please see the executive summary

8.5 Are there any further mitigations which could be considered, including any that respondents may suggest from experience in GB and RoI? Please outline how these might be implemented.

Please see section 7.1 for a summary

Gas Scenario analysis

8.6 We would welcome views on the assumptions underpinning the scenario analysis set out in chapter 3.
8.7 Do respondents consider there are other scenarios which should usefully be modelled at this time?

Please see section 4 on cost allocation.

8.8 In chapter 3 we have attempted to model the future use of gas capacity by the power sector and the impact this could have on cost allocation between the power and distribution sectors and on the reconciliation. We would welcome:
a) Commentary from respondents in the power sector on whether our assumptions on future use of gas capacity by the power sector are robust;

b) Further information from respondents in the power sector which would assist us to refine these scenarios in chapter 3 for the 24/25 gas year
c) information from respondents in the power sector which would assist us to model a scenario for the 26/27 gas year.

Impact on prices in the SEM

8.9 Do respondents have any views on the impact that short term exit capacity products would have on prices in the SEM?

Please see section 1 and 3.5

Ratchet mechanism

8.10 Irrespective of whether short term exit capacity products are introduced do you consider that the ratchet mechanism needs to be reviewed? If so why?

Please see section 3.5

8.11 Do you agree with our proposal to replace the ratchet mechanism with a capacity overrun mechanism? If not are there any other alternatives to capacity overrun mechanism you can suggest?

Please see section 3, in particular 3.2

8.12 Are there any circumstances which would warrant the retention of the ratchet mechanism?

Please see section 3, in particular 3.2

Cost recovery between power and distribution sectors

8.13 Do Respondents have any views on our assessment of the impact that the introduction of short term exit capacity products may have on how gas transmission required revenues are allocated between the power and distribution sectors?

Please see section 4

Volatility risks

8.14 Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of delayed payments to TSOs and what issues the TSOs may face as a result?

Please see section 5

8.15 If so, how should any increased risk of volatility in required shipper payments be managed following the introduction of short term exit capacity products?

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Please see section 4, 5 and 7

8.16 Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of volatility in the reconciliation payment?

Please see section 5

8.17 Does the current level, or potential future level, of volatility in the end of year reconciliation pose issues for gas suppliers? If so, in what way?
8.18 We would welcome views on the potential mechanisms to mitigate this risk of volatility set out in paragraph 5.40.

Please see section 5

8.19 Do you consider that the concept of a 'buffer account' should be explored further and do you have any additional thoughts on how this should operate?

Please see section 5.5

8.20 We would welcome a view from MEL as to whether there are monies currently held for the benefit of NI gas consumers which could be used as the initial deposit for the buffer

1 in 20 obligation and capacity booking

8.21 If short term exit products capacity were introduced, would DNOs avail of these products in order to meet the 1 in 20 obligation? Please provide reasoning for your view.

Please see the executive summary and section 2

8.22 If short term exit capacity products were available who should have responsibility for booking these - the DNOs or gas suppliers? Please explain the reasons for your view

Please see the executive summary and section 2

8.23 What would be the implications of changing the booking responsibility?

Please see the executive summary and section 2

Other:

8.24 The NI Network Gas Transmission Code includes arrangement for secondary transfer of exit capacity. Do Respondents consider that these arrangements would need to be reviewed if short term exit capacity products were available? If so, in what way?

Please see section 6

8.25 We note that a potential introduction of an ex-ante entry:exit split, which would recover a higher proportion of cost from entry capacity, could reduce the impact of the 1 in 20 obligation. Do Respondents have any views on this?

Please see section 4.2

8.26 We are interested in views on how forecasting of gas capacity bookings could be improved at entry and exit points.

Please see section 5, in particular 5.4

8.27 Are there any further matters that should be considered?

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