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Gas transmission charging review: Part II - our assessment of potential impact

Consultation

Publication date: 30 January 2015

Response deadline: 27 March 2015

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Overview:

On 12 December 2014 we published our policy position on Great Britain's (GB) gas transmission entry charging regime, proposing two key changes:

1. **introducing 'fully-floating' capacity charges for long-term capacity products; and**
2. **changing the charging arrangements for short-term capacity products.**

Publishing our policy position marked the beginning of our consultation on these changes. The consultation will close on 27 March 2015.

Our December document set out our policy proposals in full, together with the reasons why we think they would improve the current charging regime. The aim of this document is to provide more detail on our proposals, to help our stakeholders consider them and formulate their response to the consultation. We explain the background to our proposals, and give our assessment of the potential impact these proposals may have on gas transportation charges and security of supply in GB, as well as potential distributional effects. We also set out a number of questions we would like to hear your views on.

We will hold an open forum on 25 February 2015 for any questions and clarifications on the assessment of impact set out in this document. This will take place at Ofgem in London, please e-mail Gas.TransmissionResponse@ofgem.gov.uk to register.

Context

The Gas Transmission Charging Review (GTCR) was launched in June 2013 with a call for evidence. We thought a review was needed because of ongoing significant structural changes to the GB gas market since the system was designed. Emerging EU legislation to harmonise transmission charges (EU Network Code on Tariffs, 'TAR NC') will also need to be implemented in GB in the next few years and this might lead to significant changes to the GB regime.[1]

In December 2014, we gave our current view on future GB entry charging arrangements and started this consultation. We will consider the responses to the full consultation and assessment of impact before weighing up our final policy position.

Our position will feed into our discussions at the European level, as well as our considerations of other relevant charging matters, including changes to codes and to licences.

[1] Latest draft of TAR NC:
http://www.entsog.eu/public/uploads/files/publications/Tariffs/2014/TAR0450_141226_TAR%20NC_Final.pdf

The implementation deadline for TAR NC by the Member States is currently set as: 1 October 2017, or 24 months from the date the Network Code enters into force, whichever is later.

Associated documents

Gas Transmission Charging Review: our policy position on future charging arrangements, 12 December 2014
https://www.ofgem.gov.uk/publications-and-updates/gas-transmission-charging-review-our-policy-position-future-charging-arrangements

Gas Transmission Charging Review – Call for Evidence, 24 June 2013
https://www.ofgem.gov.uk/publications-and-updates/gas-transmission-charging-review-%E2%80%93-call-evidence

Literature Review - Gas Transmission Charging Review, 1 May 2013
https://www.ofgem.gov.uk//publications-and-updates/literature-review-gas-transmission-charging-review

Industry report on GTCR technical working groups, 12 September 2014
https://www.ofgem.gov.uk/publications-and-updates/industry-report-gtcr-technical-working-groups

CEPA/TPA report
https://www.ofgem.gov.uk/publications-and-updates/gas-transmission-charing-review-model-final-report

Other relevant documents are available on the dedicated GTCR section of our website (including GTCR technical working group documents)
https://www.ofgem.gov.uk/gas/transmission-networks/gas-transmission-charging-review

Contents

Executive Summary

This document provides supporting information and analysis for our policy proposals published on 12 December 2014.

On 12 December 2014 we began a consultation on two proposed changes to gas transmission entry charging. We said then that we would publish more detailed information, including our assessment of the impact of our proposals, to help stakeholders consider their responses. That is the purpose of this document.

Our concerns

The current GB transmission charging regime has served consumers well by promoting the efficient use of the network and facilitating effective competition. However, significant and ongoing structural changes to the GB gas market since the system was designed, and emerging EU legislation to harmonise transmission tariffs (TAR NC), have prompted us to conduct a review. We wanted to consider what changes to the charging regime, if any, might further the interests of current and future consumers.

When we launched our review in June 2013, we had concerns about the commodity charge constituting an increasing proportion of the total transmission charges. Our review has confirmed this trend, and concluded that this may lead to inefficient apportionment of historical network costs.

Setting commodity charges based only on gas flows, with no relation to capacity bookings made, encourages disproportionate over-booking . We think that in some circumstances, over-booking could have detrimental effects on the efficient operation of the network.

We were also concerned that commodity charges might discourage flows into GB, where price differentials would otherwise prompt imports of gas. Our earlier analysis (in 2013), and analysis carried out in this review, tend to support that view.[2]

We also found that the current level of capacity charge discounts for short-term capacity might be too high[3]. Currently short-term bookings constitute a much larger proportion of all bookings than was the case historically. As some short–term capacity is 100% discounted, a large proportion of users may avoid contributing to the recovery of some network costs. Also, these users do not face any locational signals.

Our changes

We proposed two changes in our 12 December 2014 letter:

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[2] We carried out a review of the price responsiveness of gas interconnectors in cooperation with the Dutch and Belgian energy regulators https://www.ofgem.gov.uk/ofgem-publications/75776/interconnector-flows-further-analysis-next-steps-final.pdf
[3] Short-term capacity products are: day-ahead/within-day/interruptible.

- introducing 'fully-floating' capacity charges for all users; and
- reducing the 100% discount on short-term capacity charges.

Fully-floating capacity charges would mean that the historical costs of the network are shared between all users who book capacity. They would also reduce transaction costs for cross-border trade in gas. We would expect these two effects to encourage bookings that are closer to anticipated flows, and to reduce the potential disincentive to import gas onto the GB system.

Reducing short-term capacity discounts would introduce a locational signal to users booking short-term capacity. This should help promote the efficiency in planning, operating and maintaining the network.

Our assessment of impacts

The effect of our proposed changes on individual users would depend partly on their current position in the capacity market, and partly on their future decisions. Users determine their own booking strategies and may adjust these under a changed charging regime. We have published our assessment of impact, and made our model available, so that individual users can identify the likely effects on their business.

The overall effect of introducing fully-floating capacity charges would be to reduce the average entry charge, because it would spread the historical costs more widely than at present. However, the effects on individual users would depend on their capacity bookings and expected gas flows. Users' individual total charges may increase if they hold capacity booking far in excess of what they expect to use.

We proposed that storage users would not pay the 'floating' element of capacity charges, so this change would not have an impact on them.

The effect of reducing the short-term discount would be to reduce final charges overall, compared with the current regime. This is because the adjustment to capacity charges needed to recover network revenue would be lower. However, individual users booking short-term capacity may face increased costs for that capacity, which may or may not be offset by the reduced adjustment.

Consumer impacts

Transmission entry charges amount to around 3% of consumer bills, and our proposed changes to the charging regime would not materially affect that. Instead the benefits for consumers that we expect from our changes would be dynamic: potentially avoiding future bill increases by promoting the efficiency of NGGT's network operation; and ensuring that GB security of supply, including cross-border trade in gas, is not hindered by network charges.

Our conclusion

We have assessed the expected effects of our changes against a range of relevant objectives. We think that our changes are likely to benefit consumers over time. We have published this assessment and supporting analysis to help stakeholders consider their response.

1. Gas Transmission Charging Review (GTCR)–background to our findings

Chapter Summary

This chapter provides an overview of the GTCR, as set out in our 12 December 2014 letter. It includes the reasons for the review, the context of European developments, our main findings and how we came to them.

We also highlight the most relevant conclusions of the comprehensive review of literature on economic principles and worldwide practices of network access charging applied by natural monopolies, carried out for us by Regulatory Economics Ltd.

There are no consultation questions in this chapter.

Gas Transmission Charging Review (GTCR): rationale

1.1. We launched the GTCR in June 2013 with a call for evidence. Our initial concerns were prompted by:

1. increasing reliance of National Grid Gas Transmission (NGGT) on the non-locational Transportation Owner (TO) entry commodity charge to recover its allowed revenue; and

2. the need for significant changes to the GB regime from the ongoing development of a legally binding European network code to harmonise transmission charging (TAR NC).

(1) NGGT revenue recovery – reliance on the commodity charge

1.2. Since 2006, the proportion of allowed revenue that NGGT recovers through auction sales of the national transmission system (NTS) entry capacity has been falling sharply, to just 40% in 2013 (Figure 1).[4]

[4] The 2007/08 formula year was an outlier to this trend. In October 2007 the commodity charge was set to zero due to higher than expected auction revenue in February 2007. This was largely driven by constraints experienced at Easington/Rough. These constraints created greater competition for the capacity available therefore increasing the prices bid: the weighted average bid price for Easington was 10342% compared to the reserve price, and 98% of the offered capacity in the winter period was allocated to users.

Figure 1: NGGT revenue recovery by source

	Formula year										
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
% revenue from NTS TO entry CAPACITY	83%	82%	64%	93%	80%	51%	58%	55%	45%	40%	TBC
% revenue from NTS TO COMMODITY	17%	18%	36%	7%	20%	49%	42%	45%	55%	60%	TBC

1.3. This trend in revenue recovery is driven by i) the volume of capacity bookings, and ii) price effects.

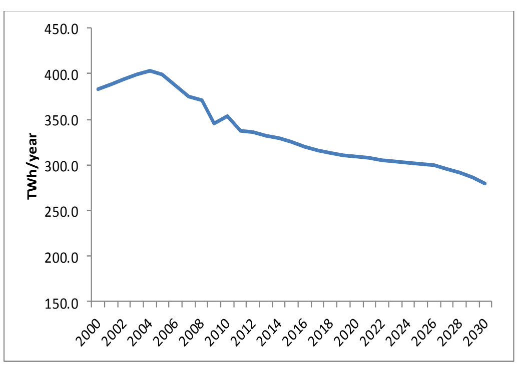
i) Volume effect: GB gas market developments

1.4. The gas transmission network in GB (NTS) has entered a fundamentally new phase. The amount of gas flowing in its pipelines is falling, and this trend is set to continue (according to NGGT's own projections, see Figure 2 below). There is abundant spare capacity on the network, due to:

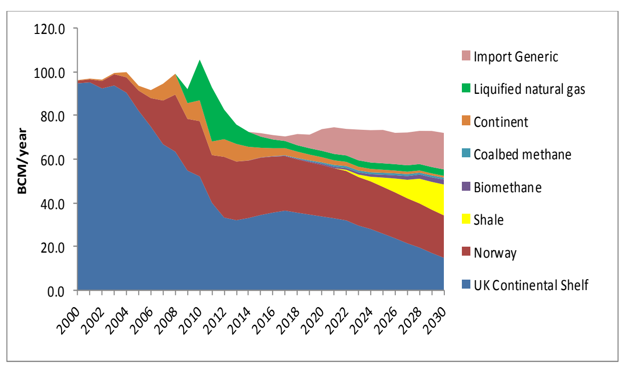
- moderating GB <u>demand</u> for gas: in 2014, demand for natural gas was 25% lower than it was in 2000;
- lower <u>supply</u> of gas: depleting UK Continental Shelf (UKCS) gas reserves means less gas entering the NTS in the North that needs to be transported to the areas of highest demand in the South; and
- <u>imported gas</u> (from Europe via interconnectors, as well as liquefied natural gas (LNG) shipped by sea): this gas enters the NTS nearer to areas of highest demand (South and South-East), and so is transported over shorter distances. The traditional pattern of North to South flows has shifted.

Figure 2: GB gas demand and supply 2000-2030

GB gas demand



Gas supply



Source: National Grid Future Energy Scenarios 2014[5]. We have presented the Gone Green scenario of supply and demand, which NGGT uses to calculate transmission charges.

1.5. We don't yet fully understand the potential impact of developments in shale gas on the transmission network. Shale site operators may seek to connect onto the NTS, although the option of connecting to the distribution networks also exists and may be more suitable, depending on the scale and location of the site. For either transmission or distribution networks, site operators would require a connection, and incremental capacity. The arrangements for securing, and paying for, connections and incremental capacity are separate from the charging regime and would not be affected by our proposals.

ii) Price effect: GB charging arrangements

1.6. The impact of declining volumes on revenue collection is further exacerbated by the existing capacity allocation and charging arrangements:

- all entry capacity is sold by auction. With high levels of spare capacity on the network, most capacity is being bought at reserve prices.

- short-term entry capacity is heavily discounted. Network users have been switching to these cheaper products rather than buying long-term entry capacity, as the risk of capacity scarcity is very low.[6]

1.7. This shift to short-term capacity would appear to be rational behaviour in response to the current charging structure.

1.8. The combination of these volume-related and price-related effects means that NGGT is increasingly relying on the commodity charge to top up the income from entry capacity sales in order to reach its target allowed revenue (Figure 3). The commodity charge has been rising sharply (Figure 4).

[5] Each year, National Grid publishes a range of different gas demand and supply scenarios. http://www2.nationalgrid.com/uk/industry-information/future-of-energy/future-energy-scenarios/

[6] For clarity, when referring to 'long-term' capacity in this document we mean Quarterly Entry System Capacity (QSEC). 'Short-term' capacity includes day-ahead/within-day/interruptible. We don't consider any changes to monthly capacity (which can be characterised as long-term). Appendix 2 provides a detailed introduction to GB charging arrangements.

Figure 3: Capacity auction revenue and Maximum Allowed Revenue

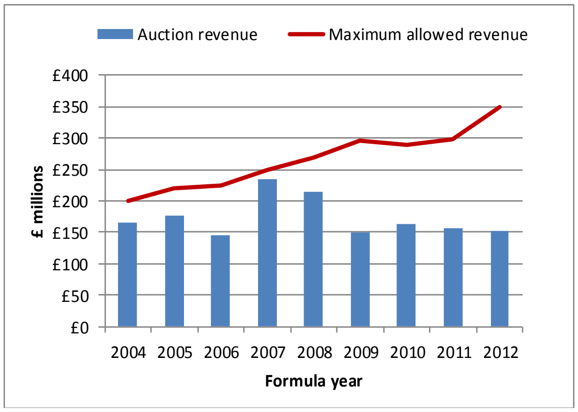
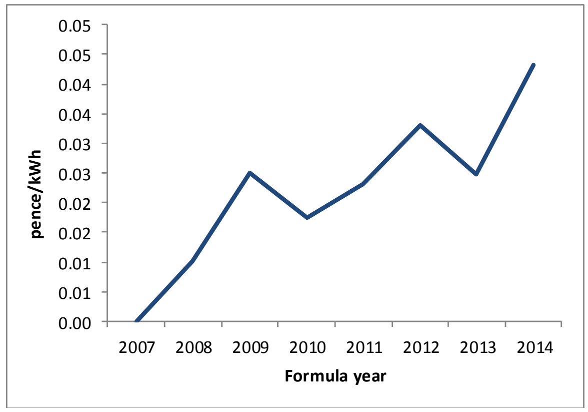


Figure 4: Commodity charge 2007-2014



Source: NGGT data

(2) European developments

1.9. Our review is taking place alongside the development of the TAR NC – European legislation aimed at harmonising gas transmission charging arrangements across Member States. The TAR NC is still being developed. What it will include is still being debated. Once it has been developed and comes into force, it will set out a date by which the provisions of the TAR NC will need to be implemented in each Member State – including the UK. The TAR NC takes precedence over domestic legislation and any inconsistencies between the domestic regulatory regime and the TAR NC will need to be removed during its implementation so that the domestic regime is compliant with the TAR NC.

1.10. The EU legislation distinguishes between cross-border interconnection points between transmission networks (referred to as 'IPs' or 'CAM points' in this document) and domestic entry points on the rest of the GB network (referred to as 'non-CAM points').[7]

1.11. The TAR NC may require, among other things, that at IPs any over- or under-recovery of revenue by the network operator (NGGT) will have to be recovered through capacity charges only, and that commodity charges should only be used to recover those costs which are associated with physical flows of gas (e.g. shrinkage costs).

1.12. To address any over- or under- recovery of revenue at IPs, a subsequent adjustment would be made to the capacity charges in the year the capacity is used. This means that the capacity charges would be 'floating' rather than pay-as-bid

[7] An earlier Network Code – Capacity Allocation Mechanisms (CAM) – made the same distinction between the cross-border and domestic points. In industry discussions, 'CAM points' and 'IPs' are sometimes used interchangeably.

('fixed'). In effect, this would mean that the price for capacity bought in previous years through a long-term auction, would, as a result of these changes, be determined in the year in which that capacity is used.

1.13. Were that to be mandated at IPs, it would require significant changes to the existing GB entry arrangements. The interaction between the GTCR and TAR NC development and implementation timelines is discussed in more detail in Chapter 6.

GTCR: findings

1.14. The design of transmission charges is very important. It can have significant implications for the network operator's and network users' businesses. It can influence competition between different supply sources, affect the efficiency of network operation and NGGT's investment decisions, as well as cross-border trade and security of supply. All of these have the potential to affect consumer bills.

1.15. The persistent upward trend in the commodity charge has prompted concern about the extent to which the existing charging arrangements are efficient or cost-reflective. The original policy intent for the commodity charge was to correct residual under-recoveries. It was not envisaged as the main revenue recovery mechanism (see Appendix 2 – Introduction to GB charging regime).

1.16. The existing charging arrangements worked well under the conditions of growing demand for gas, and performed well during the periods of capacity scarcity on the network. However, we are not convinced these arrangements remain effective in the context of ongoing significant structural changes to the GB gas transmission network.

1.17. We are concerned about the long-term stability and flexibility of the GB regime. We think there are particular areas of weakness in the current arrangements:

Inefficient allocation of historical network costs

1.18. The NTS is a natural monopoly, and a high proportion of its costs are fixed. The NTS asset lives are long, varying between 40-50 years. This means that the cost of past investments incurred by NGGT to provide these shared assets cannot be attributed to individual users.

1.19. Currently, these historical network costs are largely socialised across network users through the commodity charge. Because the commodity charge is based on flows, this means that the contribution of users to the recovery of the fixed network costs is flow-based. This means that some users, who have booked capacity but decided not to flow against the booking, contribute less than those whose flows are closer to their bookings. This is despite the fact that all users benefit equally from the existence of a reliable, safe network.

1.20. Where users don't face the true cost of network access, this weakens the signal and the incentive to book the capacity and use the network efficiently. We have evidence suggesting that the existing arrangements result in over-booking of entry capacity and affect cross-border trade in gas. We think these inefficiencies could be detrimental to the interests of consumers.

Over-booking of capacity

1.21. Every year NGGT provides us with data relating to the operation of the network over the winter months (October to March). This includes the flows and bookings data for each entry point.

1.22. Figure 5 below shows that the total winter flows across all entry points (October to March) as a proportion of capacity bookings have been decreasing year on year. The data in shows that October had the lowest flows compared with capacity bookings over the past six winters.

Figure 5: Total winter flows as proportion of entry capacity bookings

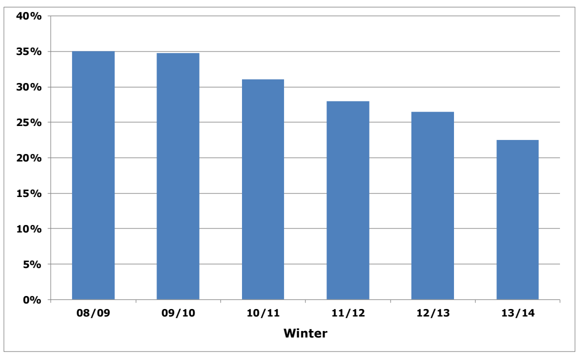
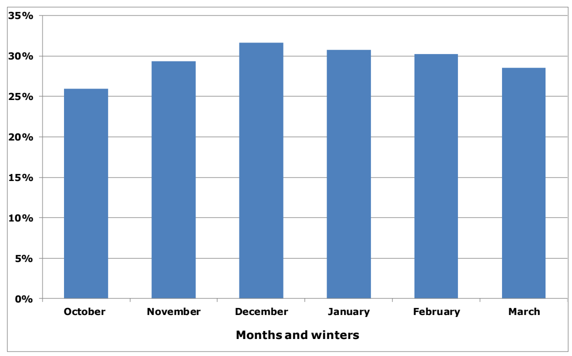


Figure 6: Monthly flows over 6 winters as proportion of entry capacity bookings



Source: NGGT data

1.23. In 2013/14 the total winter flows on the network only constituted 22.5% of the capacity booked for that period, compared to 35.6% in 2008/09. The highest proportion of flows to bookings was at Easington (40%). Hornsea storage entry point was amongst the lowest, at 2.4%.

1.24. We are concerned about the potential challenges this may present for NGGT in ensuring continuing operational efficiency of the network, as well as wider investment decisions. In turn this could affect consumer bills.

Effects on cross-border trade in gas

1.25. In 2013 we carried out a review of the price responsiveness of gas interconnectors.[8] The findings reinforced our concerns about the level of the commodity charge. We found evidence that a high commodity charge introduced a bias against landing gas in GB. We identified a material number of occasions when, despite the wholesale gas price being higher at the GB hub than at the Belgian hub, Interconnector UK exported gas from GB to Belgium. Distortions in cross-border gas trade can lead to potential adverse implications for GB security of supply, and GB consumers.

Suitability of short-term discounts

1.26. A central issue identified in our review is the tension between setting charges which encourage short-term efficient utilisation of the gas transmission network, while also allowing for the recovery of past investments in the infrastructure assets.

1.27. The rationale for the existing structure of short-term capacity discounts is the economic principle of the efficiency of marginal cost pricing. However, we also know that a natural monopoly cannot recover its full costs by setting prices at the marginal cost.

1.28. Maintaining current levels of discounts against the background of excess capacity on the network and the subsequent shift in the majority of users' buying strategies from long-term to short-term capacity booking does not appear sustainable or efficient.

1.29. We are also concerned that the 100 per cent discounts on daily products limit the ability of NGGT to provide users with robust locational pricing signals, which are needed to incentivise the optimal use of the network. This concern has now become acute because:

- the daily capacity has become the product of choice for a large number of users; and

- the pattern of flows on the network is likely to become more uncertain in the future, given the diversity of supply sources (UKCS, interconnector flows, storage, LNG).

1.30. This could impact the usefulness of capacity bookings signals in planning and maintaining the network.

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[8] In cooperation with the Dutch and Belgian energy regulators https://www.ofgem.gov.uk/ofgem-publications/75776/interconnector-flows-further-analysis-next-steps-final.pdf

Literature review

1.31. To help us identify potential solutions to the problems outlined above, we appointed an independent consultancy (Regulatory Economics Ltd) to carry out a comprehensive review of literature on economic principles and worldwide practices of network access charging applied by natural monopolies. To ensure the relevance of this research to the GTCR, we asked the consultancy to focus on access charging in a context of excess supply, with a particular focus on gas transmission networks.

1.32. In its report published on our GTCR website[9], Regulatory Economics Ltd point out that the structure of GB gas market arrangements is unique, and conclude that:

"It is clear that a single instrument – the access price – can often be called upon to fulfil multiple objectives simultaneously, such as: allowing for efficient utilisation of a network; ensuring cost recovery for a network operator; providing appropriate signals for investments by network operators and network users; and correcting for any distortions in related markets.

In practice, this creates a difficult balancing exercise and can require a regulator to balance and trade-off the objectives related to allocative efficiency against those of dynamic efficiency. In addition, distributional issues can become relevant; particularly the question of how the burden of cost recovery is allocated among different types of network users. More generally, the fact that a balance needs to be struck between sometimes competing objectives provides an explanation for why regulators sometimes adopt approaches which are pragmatic and do not necessarily accord with the strictures of economic theory."

1.33. The economic literature identifies the trade-offs involved, and the potential implications of different courses of action in terms of static and dynamic efficiency. However it does not offer any concrete solutions to how this trade-off should be resolved in practice.

1.34. Some technical and policy reports – including the impact assessment for the Framework Guidelines (which set out the summary of what TAR NC should contain once it has been developed) on harmonised transmission tariff structures prepared for ACER – consider that, where there is no growth or congestion on a gas transmission network, tariffs should have a retrospective focus. They suggest that the primary concern should be allocating the historical costs of investments among network users in ways that accord with notions of fairness.[10]

1.35. This is in contrast to a situation "with network growth or congestion, where capacity is scarce and tariffs face the primary challenge of ensuring efficient

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[9] https://www.ofgem.gov.uk/gas/transmission-networks/gas-transmission-charging-review

[10] 'Impact Assessment for the Framework Guidelines on harmonised transmission tariff structures', the Brattle Group, August 2012

allocation. The relevant cost concept is prospective, related to scarcity value and the marginal cost of construction (long-run marginal cost)."

Gas Transmission Charging Review: current status

1.36. From the conclusions of the literature review, engagement with the stakeholders (see the section below) and participation in discussions in Europe, we identified potential changes to the charging regime to address the problems identified above.

1.37. We recognise that external developments, the TAR NC in particular, may lead to changes in the GB market arrangements and the current regulatory framework. However, the exact form of these changes and the scale of their impact on transmission charging regime are uncertain. We also note that there is always potential for future external developments to have implications for how well GB transmission charges serve the interests of consumers. We will continue to consider the consequences of European developments for the arrangements in GB.

1.38. We are now at the final stage of the GTCR. We have considered various charging options, and published our policy position on future GB entry charging arrangements on 12 December 2014.[11] The options we have considered, and the changes we are proposing, are discussed in detail in the following chapter.

GTCR - stakeholder engagement up to now

1.39. In conducting this review and reaching these findings, we engaged with the wider stakeholder community. We held three wider stakeholder events to provide general progress updates and seek feedback in December 2013, July and August 2014. We provided regular updates throughout 2014 at various industry meetings including the Joint Office of Gas Transporters, the Gas Forum and the Gas Storage Operators Group.

1.40. In July 2014 we set up an industry group (GTCR technical group) to help us and our consultants to develop a tool for modelling various options for charging arrangements, as well as the quantitative impacts of those options.[12]

1.41. We presented the initial modelling results at an open industry event on 14 October 2014. Agendas, papers and minutes for the technical group meetings are available on our GTCR website. The group's conclusions report, delivered by the Gas Forum, can also be accessed via our website.

[11] https://www.ofgem.gov.uk/publications-and-updates/gas-transmission-charging-review-our-policy-position-future-charging-arrangements
[12] Cambridge Economic Policy Associates Ltd (CEPA) and TPA Solutions Ltd

2. Explanation of our proposed changes to the charging regime

Chapter Summary

This chapter sets out more fully our proposed changes to the charging regime. We discuss how these proposals seek to address the shortcomings of the current regime identified in the previous chapter.

We also set out why we have not pursued other options for addressing the shortcomings of the existing arrangements, without moving to fully-floating tariffs.

Question box

Question 1: What are your views on our proposed changes?

Question 2: Do you agree with our reasons for rejecting the alternatives? If not, please explain why.

Change proposals

2.1. Following our charging review, we think the following changes are needed to improve the efficiency and cost reflectivity of the transmission charges:

- introducing 'fully-floating' capacity charges for long-term capacity products;
- changing the charging arrangements for short-term capacity products:
    - all users will pay the full 'floating' capacity charge component, to contribute to the recovery of the historical network cost;
    - the reserve price discount on short-term capacity products will be less than 100% of the long-term capacity reserve price.

Fully-floating capacity charges

2.2. We propose that NGGT should recover the historical network cost through an adjustment to the capacity charge, based on bookings of both long- and short-term capacity. Where NGGT under- (or over-) recovers its allowed revenue based on the bookings at capacity auctions, the price paid by a user would 'float' up (or down) in the year the capacity is used to adjust to the allowed revenue . This would mean that the true cost of the network would be explicitly reflected in the access charge. This adjustment would exclude any genuine variable cost – NGGT would continue to recover this through a small flow-based charge.

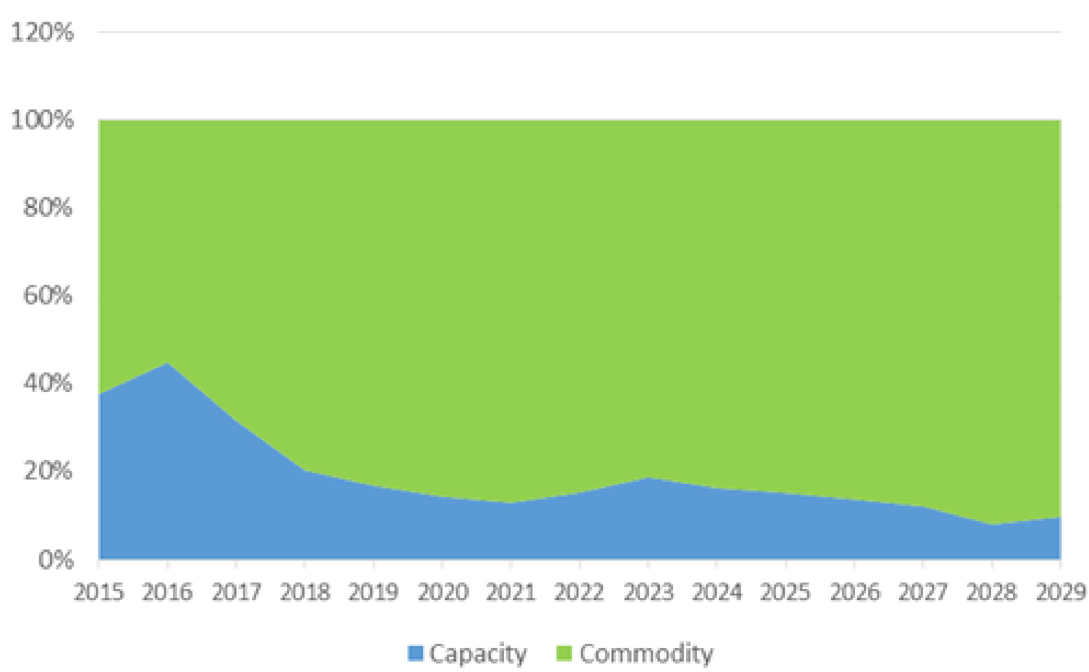
2.3. Under our proposal this 'top-up' adjustment would not be charged to storage users, largely preserving the existing storage arrangements. Storage users would pay the new flow-based charge, but this would be far smaller than the current commodity charge, as it would be set to recover only actual flow-related gas transportation costs.

2.4. One potential argument against fully-floating capacity charges may be that they would reduce the transparency of prices at the capacity allocation auction, and undermine the fixed price principle. However, we think this would be countered by the following two factors –

a) Currently, the price a user ultimately pays is not fixed, but is increased significantly by the addition of the variable commodity charge. This trend is likely to continue, as illustrated in Figure 7 below; and

b) the effectiveness of price discovery (ie ensuring that, where existing entry capacity is scarce, those users who value the capacity most get it) in the existing auctions is questionable, given the presence of significant surplus capacity.

Figure 7: Projected capacity/commodity charge split of revenue recovery



Source: CEPA/TPA Solutions model (see Chapter 3 for detail)

2.5. We think changing to fully-floating capacity charges would help address the inefficiencies in current arrangements by:

- reducing the over-booking of capacity

  The change will help ensure that users face the true cost of network access, including the fixed costs NGGT has incurred in making available a reliable, safe network. This should strengthen the signal and the incentive for users to book capacity, and use the network, efficiently.

- better facilitating cross-border trade

  Under the floating capacity charging arrangements, the remaining flow-based (commodity) charge would be set to recover only the actual flow-based costs. This means that the flow-related transaction costs of cross border trade would become more cost-reflective. We think this should improve cross-border trade in gas.

Reduce 100% discounts on short-term capacity

2.6. We propose to reduce the 100% discounts for on-the-day and interruptible capacity products. We expect the exact level of discounts (including for day-ahead) to be worked out by the industry through a consultation process.

2.7. As discussed in the previous chapter, with high levels of spare capacity on the network, the tension between setting charges to encourage short-term efficient use of the NTS and ensuring efficient revenue recovery has become more acute. We also think that the cost to NGGT of accommodating the widespread behavioural shift of users towards short-term bookings is not insignificant.

2.8. We also consider that if the trend for favouring short-term capacity continues and even increases, NGGT may need to be able to provide locational signals to these users. Reducing the current 100 per cent discounts would introduce a locational signal, which could help to ensure the network is used efficiently.

2.9. A better compromise needs to be reached. The short-run marginal cost principle should continue to be recognised (ie short-term discounts may still be justified), but the objective of efficient, fair, non-discriminatory cost recovery should also be considered.[13]

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[13] In 2010 we rejected a proposal from NGGT to remove the discounts on the reserve price for the daily entry capacity auctions (both day-ahead and within-day). The summary of our decision is in Appendix 4 - Modification Proposal NTS GCM 19 'Removal of NTS Daily Entry Capacity Reserve Price Discounts'.

2.10. Improving the ability of NGGT to signal the most cost-effective use of the NTS would help ensure that the network service is provided at value for money to existing and future consumers.

Alternatives to our proposed changes

2.11. We explored other possible ways of addressing the problems identified above, without moving to fully-floating charges. We explored the option of inflation-adjustment of the payable price on long-term capacity products, with and without changes to short-term discounts.

Adjust the payable price on long-term capacity products to take account of inflation (with/without changes to short-term discounts)

2.12. Network users can buy entry capacity up to 17 years ahead of use. Network users pay for the capacity in the year of use, at their original auction bid price, with no adjustment for the effect of inflation since the auction.

2.13. Allowed revenues are adjusted for inflation. Consequently, the gap between capacity income from long-term bookings and allowed revenues increases over time. This under-recovery is then socialised amongst all users – even though it is 'created' by a subset of users 'under-paying' for the capacity they acquired previously. To address the issue of under-recovery, and reduce the commodity charge, the users' bid prices could be uprated by inflation (for example by applying the RPI index).

2.14. However, while this change may go some way to address the under-recovery of revenue, it does not address our concern that all users are not facing the true cost of the network. This is because under this option, the top-up charge would still be based on flows, not bookings. As a result, it would not address the shortcomings of the regime identified above.

Dual regime – TAR NC implementation at IPs only

2.15. The current drafting of TAR NC requires us to implement changes to charging regime at IPs only, with the option of keeping the rest of our domestic regime as is.

2.16. As discussed above, following our review, we think the current regime has flaws and our preferred option is for it to change to fully-floating.

2.17. For completeness, we have modelled all the possible changes described above. We set out our initial quantitative and qualitative assessment of the effects these changes may have on the levels of transmission charges, cross-border trade, and the distributional impacts in the next chapter.

3. Impact assessment of these proposals

Chapter Summary

This chapter sets out our quantitative assessment of the impacts of the different charging options considered on transmission entry charges and potential distributional effects on the network users.

We also summarise our qualitative assessment of other relevant impacts (eg cross-border trade in gas).

Question box

Question 1: Do you think we have identified the relevant quantitative impacts?

Question 2: Do you think we have modelled the impacts appropriately?

Question 3: Do you think we have identified the relevant qualitative impacts?

Question 4: Do you have any further evidence of the potential impacts of our proposed changes not covered by our analysis?

3.1. Our policy options fall under four broad categories:

1) Maintaining the current regime;

2) Incremental changes to the current regime: applying inflation to long-term products and reducing 100% discounts to the capacity charge for short-term products (everyone pays the same commodity rate.[14]) These two changes are considered separately and in combination;

3) Fully-floating capacity charges applied to both long- and short-term capacity at all NTS entry points combined with reduced discounts for short-term products. At the time of modelling, TAR NC was still in development, and the exact approach to calculating floating charges was not finalised. We have calculated the possible fully-floating charges as follows:

[14] Except storage users, who don't pay the commodity charge

For long-term capacity:

i. derive Long Run Marginal Costs (LRMCs)for all entry points in line with the distance-to-virtual-point cost allocation methodology;
ii. apply secondary adjustment to LRMCs to ensure NGGT gets allowed revenue – this is done by adding a constant 'float' to these values.[15]

For short-term capacity:

i. discount the relevant LRMCs calculated above;
ii. apply secondary adjustment to the discounted LRMCs to ensure NGGT gets allowed revenue – this is done by adding a constant 'float' to these values. That is, the floating element is not discounted.

The latest draft of TAR NC states that the short-term discount needs to apply to the total capacity charge – that is, the floating element should also be discounted.[16] This means that to be compliant with the TAR NC, the final design of short-term charges may be different to the one modelled for the purposes of this assessment. We believe that the results of our modelling remain relevant.

4) Examples of a dual regime, for which IPs are subject to fully-floating charges (as in 3 above) and the existing capacity/commodity charge arrangements remain at all other entry points. Again, the inflation and discounts options are applied separately and in combination to all entry points.

Quantitative assessment

3.2. The objective of this assessment is to provide evidence of the potential quantitative impact of the options we are considering. We have focused on the impacts in the following areas, over the modelled period 2018-2029:

- level of entry transmission charges (ie capacity and commodity)[17]; and
- distributional impact on network users.

[15] For the purposes of modelling, calculations are based on TO revenues. TAR NC may contain provisions to include both TO and SO revenues.

[17] As discussed in the previous chapter, even under the fully-floating regime NGGT would still maintain a small flow-based charge to cover genuine flow-based costs (eg shrinkage). We have not modelled this small based charge. Instead, we adjusted the total TO allowed revenue to be recovered by TO entry charges by removing pure flow-based costs.

3.3. This assessment has been informed by the charging model developed by independent consultants, Cambridge Economic Policy Associates (CEPA) and TPA Solutions, with input from the industry (GTCR technical working group).[18] An overview of the model is provided in Appendix 5 – GTCR model. The modelling necessarily includes a number of simplifications to make the analysis manageable. Consequently, the effects should be read as indicative, rather than specific.[19]

Base case

3.4. Commonly in impact assessments, the effects of alternative options are quantified by reference to a single counterfactual. The final structure of the TAR NC (i.e. whether GB can maintain the existing regime at all points, or minimum implementation will be enforced at IPs) is uncertain. Therefore, we initially set out to compare our results against two counterfactuals -

- Base Case 1: a continuation of the current charging regime at all points.
- Base Case 2: a dual regime in which a fully-floating capacity charge has been mandated at IPs (ie Bacton[20]), from 2017. All other points are assumed to continue to operate under the current fixed price capacity, variable commodity charge regime.

3.5. However, having reviewed the model's key outputs for Base Case 1 and 2 – entry capacity and commodity charges over time, by entry point, revenue recovery by user group, etc. – we have found them to be almost identical.[21] This is not surprising. Since only one entry point on the network has a different charging structure, the impact on charges paid across the whole system is likely to be insignificant.

3.6. For ease of presentation, we have therefore settled on having one base case – the current regime. Our decision was also influenced by the fact that we don't yet know how a dual regime would work in practice. For modelling purposes, the consultants designed one way it could work – but their approach may not necessarily be fully compliant with the final TAR NC.

Options modelled

3.7. Table 1 below summarises all the options modelled with and without inflation for different discount levels. For the purposes of modelling and this assessment, the term 'short-term' encompasses within-day / day-ahead / interruptible / monthly

[18] For papers and minutes of these meetings, please see our GTCR website
[19] Ie whether charges increase/decrease, whether the rate of change is small (e.g. 10% or less) or significant (e.g. 70%).
[20] Moffat is the only other point on the NTS classified as an IP. However, it is an exit point only, and therefore out of scope for our purposes.
[21] See Appendix 6 – Additional modelling results; Figure A6—1, Table A6-2, Figure A6-2.

capacity products and 'long-term' means QSEC only. For the remainder of this document, we use 'QSEC' and 'long-term' interchangeably.

3.8. Monthly capacity can be characterised as a 'long-term' booking. The model tries to make the main distinction between QSEC and other bookings, and classifying monthly capacity as short-term helps with that. Under our proposals, the changes to discounts would apply only to day-ahead, within-day and interruptible capacity.[22] Monthly capacity pricing would not change from the current arrangements.

Table 1: Options modelled

		Base case	Dual regime	Fully-floating
Short-term discount* (see notes 1 and 2)	Current: 100% discount for within-day/interruptible 33.3% discount for day-ahead	a,b	a,b	n/a
	90% for all short-term	a,b	a,b	n/a
	30% for all short-term	a,b	a,b	n/a
	0% for all short-term	a,b	a,b	n/a
Premium*	120% for all short-term	a,b	a,b	n/a
Inflation indexation	a	No changes, prices aren't adjusted for inflation		
	b	Prospective inflation: applies to existing and new bookings, from policy introduction (2018)		

*the change to short-term discounts applies to within-day / day ahead / interruptible capacity products only; monthly capacity pricing remains the same

Note 1: 90% discount means that a shipper pays 10% of the QSEC reserve price (or auction clearing price if it goes above the reserve)

Note 2: This document concerns GB policy, and is consistent with the UNC terminology. Under TAR NC terminology, a 90% discount would be described as a '0.1 multiplier'

[22] Ie the discount applied to day-ahead/within-day/interruptible is the same, for the purposes of modelling and this assessment. For the 90% discount policy option, this means a more generous discount for day-ahead capacity (currently discounted at 33.3%).

3.9. The modelling results for all the options are set out in Appendix 6 – Additional modelling resultsfor transparency. We are presenting a smaller set of options in detail in this chapter. This is because, having done the modelling, we discovered that:

- the policy option of uprating long-term bookings by inflation doesn't materially affect average entry transmission charges (Table 2 below) or revenue recovery by user group (see Appendix 6, Figure A6-3).[23]

Table 2: Average annual capacity charges (£pence/KWh)

	Base case/current regime			Dual regime		
	No inflation	Inflation	% change	No inflation	Inflation	% change
Current	0.0322	0.0319	-0.93%	0.0329	0.0327	-0.79%
90%	0.0315	0.0312	-0.95%	0.0322	0.0319	-0.96%
30%	0.0270	0.0267	-1.11%	0.0277	0.0274	-1.12%
0%	0.0243	0.0240	-1.23%	0.0250	0.0247	-1.24%
120% premium	0.0239	0.0236	-1.25%	0.0245	0.0242	-1.06%

Source: CEPA/TPA Solutions model

- Base case and dual regime case produce broadly similar results in aggregate – as explained above (3.4-3.6).

- 0% discounts and 120% premium on short-term capacity have been modelled for completeness, and do not represent our preferred policy approach at this stage (see Appendix 6, Figure A6-4 and Figure A6-5)

3.10. Therefore, we have limited our presentation here to the effects of the key four options out of the 25 modelled:

i. Base case, current discounts;

ii. Base case with 90% discounts;

iii. Fully-floating, current discounts; and

iv. Fully-floating with 90% discounts.

[23] Any impact would be concentrated on individual users with large amounts of QSEC bookings, over long periods of time.

3.11. The modelled impacts are sensitive to the input assumptions made. We have investigated some of these sensitivities for the four options above:

- Future Energy Scenarios. Our model uses the Gone Green scenario to calculate entry charges (as NGGT currently does) and the Slow Progression scenario for modelling network users' behaviour[24]. Some of the GTCR technical group members suggested that the results of the model may change depending on the scenario used. Under the Slow Progression, there is an increased role for gas where the development of renewable resources is slower, compared to the Gone Green scenario. We have re-run all the results under the Gone Green scenario only.

- Treatment of storage. We considered the level of transmission charges when storage users were treated in the same way as other users under the fully-floating regime – that is, paying the floating adjustment.

Interpreting the model

3.12. Because of the complex nature of the gas market, there are some inevitable shortcomings of the modelling approach. These are described below before we present the results of our quantitative analysis.

3.13. Some of the limitations of the current approach and the options for additional analysis are documented in CEPA/TPA's report. Based on attendance at the technical working group, the Gas Forum highlighted some further limitations in its report.[25] In using the model to inform our analysis, we have also identified how some of the necessary simplifications have influenced the results. The most notable shortcomings and assumptions identified are:

- NGGT's allowed revenue is set to remain constant in 2009/10 prices up to 2029[26], and the allocation of system operator (SO) and transmission owner (TO) allowed revenue remains unchanged. [27]

- LNG is assumed to be the 'swing source' in the model's dispatch calculations. This influences the revenue recovered at different entry points, depending on supply source. An alternative dispatch schedule would result in different flows at different points over any given year.

[24] We have discussed using two different future energy scenarios in the model at the GTCR technical group. This was considered reasonable by the participants.
[25] http://www.gasforum.co.uk/news/5-news/126-gas-transmission-charging-review-technical-group-conclusions-report#sthash.5XHByth2.3qZm5Gm8.dpbs
[26] This is equivalent to around 2.5%-3% year-on-year increase.
[27] This refers to the percentage split of the TO and SO allowed revenue set out in RIIO-T1.

- All entry points and supply sources are assumed to have the same probability curve for the risk of constraint. This effectively assumes that all users have the same risk appetite regardless of supply source or entry point.

- The potential for actual physical constraints within the network (at entry and exit) is not considered by the model.

- The model represents a static picture of the physical transmission system. This means that it does not explore new or additional sources of supply or changes to the characteristics of entry points, including any potential new entry points over the modelled period.

- Due to the uncertainty as to what the final provisions of the TAR NC will be at the time of modelling, our approach to the dual regime may not be accurate. Whilst we think that the aggregate system results are robust, we have less confidence over the precise levels of charges at the IP (Bacton CAM).[28]

3.14. We have considered whether our analysis is adequate to support robust, evidence-based policy development, or whether we need to undertake additional analysis. We do not propose to undertake further modelling at this stage.[29] The questions being addressed by the model are complex, and we have concluded that it is highly unlikely that any other model would provide materially more robust findings than the current model without significant delay to the process (if at all). Overall, therefore, we do not think it is proportionate, or in consumers' interests to extend the process further and undertake more modelling on the broad changes that we are proposing.

3.15. The modelling results must be interpreted taking the above limitations into consideration. Therefore, while we consider that the modelling results provide a view of the relative impact of the modelled options, we acknowledge the limitations. The results only provide an approximate guide as to the likely 'real world' impacts with a broad sense of the magnitude of impacts. It is therefore also important to consider the qualitative analysis supporting this assessment.

3.16. Overall, the model produced indicative effects on charges that were in line with our expectations, in relation to each change modelled. Industry stakeholders who worked with us as the model was developed also broadly felt that the modelled effects of each change were plausible, and in line with their expectations. The model allows for closer analysis of how each charging change would feed through to a user's paid charge.

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[28] In December 2014, we consulted on splitting Bacton entry point into two – an IP (CAM point) and domestic (non-CAM point). This is to comply with the Capacity Allocation Mechanisms network code. The consultation closed on 16 January, and we will publish our decision in early February 2015.

[29] Table A5 - 1 overleaf provides a more detailed explanation of the model's limitations, including some of the early industry views on them (taken from the GTCR technical group's conclusions report, presented by the Gas Forum).

Impact on entry transmission charges

3.17. In this section we present the results for the level at which charges can be set under different regimes to recover NGGT's allowed revenue. The results allow us to compare the relative cost of entry to the NTS under different scenarios, but do not accurately represent what individual users may actually pay. This depends on a range of shipper-specific factors, including the year in which capacity was purchased, the level of each shipper's contractual commitment and their subsequent flow decisions. We discuss this further in the section on distributional impact.

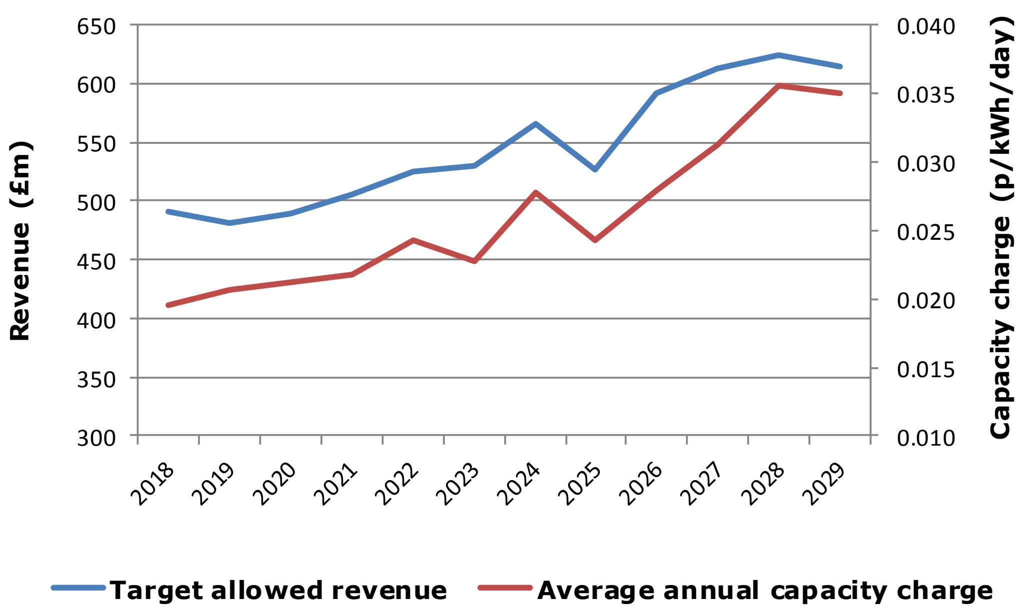
Entry charges over time

3.18. Projected changes in allowed NGGT revenue are a key driver behind year on year changes in charges that the analysis shows.

3.19. The NGGT's maximum allowed revenue t is projected to increase in cash terms over the modelling period (2018-2029), under all options. Up to 2021 we have used the actual base revenue figures set out in RIIO-T1. For the remainder of the modelled period – up to 2029/30, we assume the allowed revenue remains constant in 2009/10 prices.

3.20. Figure 8 below shows how the modelled charges change over time in line with target allowed revenue. The example shown is of the fully-floating option, 90% discounts, with 2018 as the assumed implementation date of the new charging arrangements.

Figure 8: trends in allowed revenue and entry transmission charges 2018-2029



Source: NGGT and RIIO-T1

Average level of entry charges

3.21. Figure 9 below shows the average QSEC entry charge (solid green line) and QSEC entry charges for key entry points (coloured bars) for 2021 under two of the key scenarios: i) base case with existing discounts and ii) fully-floating regime with 90% short-term capacity discounts. In this example, the users are assumed to flow all their booked capacity.

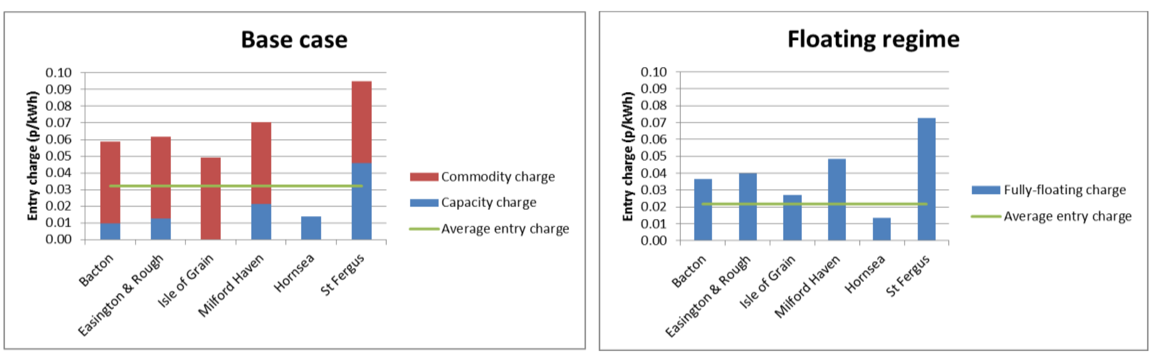
3.22. The charges for the selected entry points are taken directly from the model. The average charge is derived as follows:

- for base case: average commodity rate[30] + average QSEC capacity charge across all entry points (including storage);
- for fully-floating: average floating capacity charge across all entry points (including storage, who don't pay the floating adjustment).

3.23. The blue bars represent capacity charges. The red bars represent the commodity charge cost - essentially, they reflect the shipper's decision on how much to flow.

3.24. This shows that the average entry charges for QSEC are set at a lower level under fully-floating arrangements. This is to be expected, as the total allowed revenue is collected based on all bookings, not flows, thus increasing the size of the charging base and spreading the costs across all users.

Figure 9: average entry charges, QSEC (flows=100% of bookings)



Source: Ofgem analysis based on CEPA/TPA Solutions model

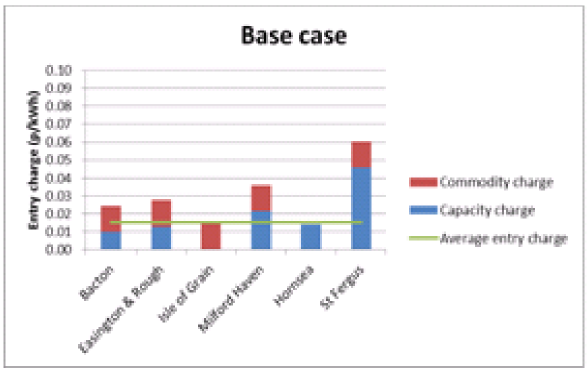
3.25. The same trends are observed for the other two scenarios – base case with 90% short-term discounts and fully-floating regime with the current discounts. This

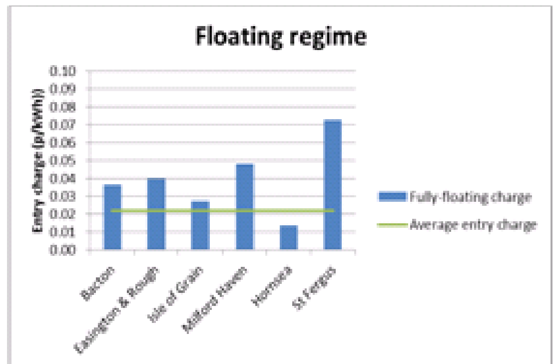
[30] This is the average of 0 and commodity charge, to capture the fact that storage users' commodity charge is zero.

suggests that the main reason for the difference in the level of average charges between the scenarios is the move to capacity-based charges.

3.26. Figure 9 also shows the degree of variation in the level of charges across the key entry points on the system[31]. In addition, the comparison requires assumed flows to bookings ratio to calculate the commodity charge. When another ratio is assumed, the conclusions change (see Figure 10 below). This means that while the average charge is useful from a policy-maker's perspective as a high-level indicator of the impact of different regimes, it may be of less use to individual network users.

Figure 10: average entry charges, QSEC (assumes flows=30% of bookings)





Source: Ofgem analysis based on CEPA/TPA Solutions model

Distributional impact – individual network users

3.27. Informed by the modelling, we have identified the main parameters which determine how a particular user may be affected:

- Level of contractual commitment:
  - Proportion of long-term bookings in the portfolio;
  - Absolute size of QSEC booking, length of the booked period.
- Flows as proportion of bookings; and
- Location of entry point (for short-term only).

[31] For example, at Hornsea, it is 0.6% of the wholesale gas price, compared to 3.15% at St Fergus (in 2021, under the fully-floating regime).

3.28. The impact on the user will depend on the degree of control it has over these parameters. The more opportunity there is for a behavioural response, the greater the scope for any potential adverse impacts to be mitigated.

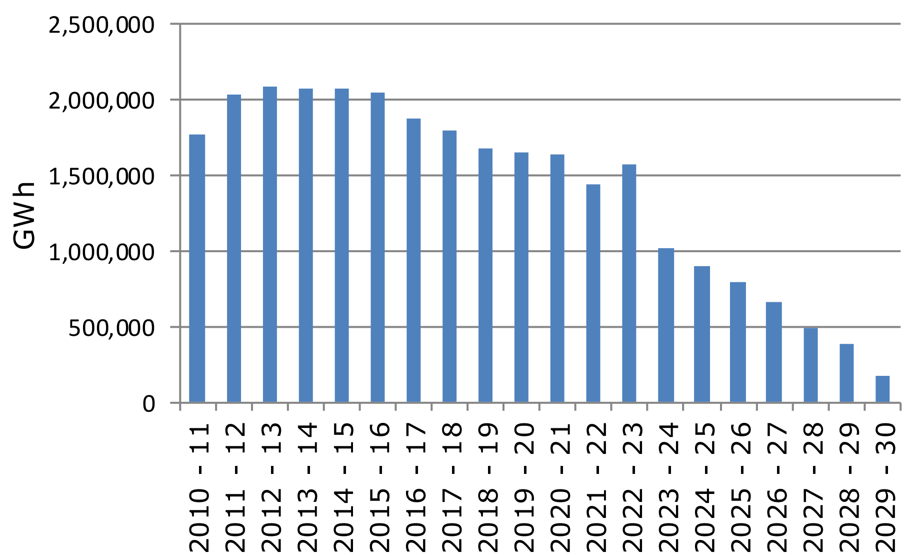
Contractual commitment

3.29. Subject to further policy refinements and to consultation responses, our preferred implementation approach would be for the new charging arrangements to apply to all contracts from the date the changes come into effect. So if a user bought capacity for a period 2010-2020, and the fully-floating regime comes into effect in October 2018,they would pay the fully-floating charges for the proportion of that capacity already booked for the period from October 2018.

3.30. Users with existing long-term contractual commitments would have limited ability to adjust their behaviour in response to the changes. This means that the users most affected by the change to fully-floating tariffs would likely be amongst those with higher proportion of long-term bookings in their portfolios, higher absolute volume and longer contract duration.

3.31. We have examined NGGT data on the existing QSEC bookings up to 2029/30 to understand the magnitude of a potential impact.[32] Long-term capacity bookings have been declining steadily. This is illustrated in Figure 11 below.

Figure 11: Existing QSEC bookings (GWh per year)



Source: NGGT data

[32] As of March 2014.

3.32. The proportion of QSEC booked by storage users is increasing, from about 40% of the total QSEC bookings (ie by all users) in 2013/14 to around 60% in 2029[33]. Under our proposals, storage users would not pay the adjustment to the capacity charge so their final charges for QSEC capacity will be unaffected. This further limits the impact of any potential changes on holders of existing contracts.

Flows as percentage of bookings

3.33. Under the existing arrangements, if a user doesn't flow gas against its bookings, it doesn't pay the commodity charge. This would change under the fully-floating arrangements, where the charges would become capacity-based and users would still be liable to pay them even if they don't flow gas.

3.34. In terms of impact, those users flowing close to their bookings are likely to see their system entry costs fall, or at least remain the same under the fully-floating arrangements, relative to the current regime. However, those who flow much less than they have booked would have been better off under the existing arrangements, especially if the commodity charge continues to increase as a proportion of the total entry charge.

3.35. To illustrate this effect, we have taken the average capacity charges and the relevant commodity charge generated by the model, and applied different flow/booking ratios to calculate total entry costs under different regimes.[34]

3.36. We have explored three scenarios, where users flow 30%/60%/100% of their bookings. These scenarios have been informed by NGGT data on bookings and flows for 2012/13. The data showed a wide range of flows to bookings ratios (between 0 and 1) across different entry points and different users at the same entry point.

Figure 12 and

3.37. Figure 13 overleaf show how the average charges across entry points vary over time by the flows to bookings ratio and the choice of long- or short-term product. The model shows that users whose bookings are equal to their flows would pay lower tariffs on average under the fully-floating policy options. If a user continues to over-book capacity at the same rate, as shown in both the long- and short-term examples where flows=30% of bookings, their average costs are likely to increase.

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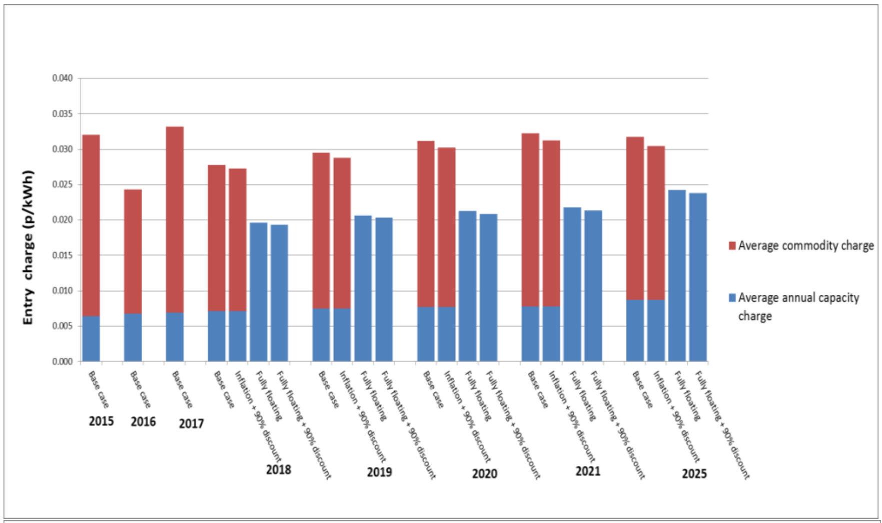
[33] We assumed 25% of bookings at Easington are for storage.

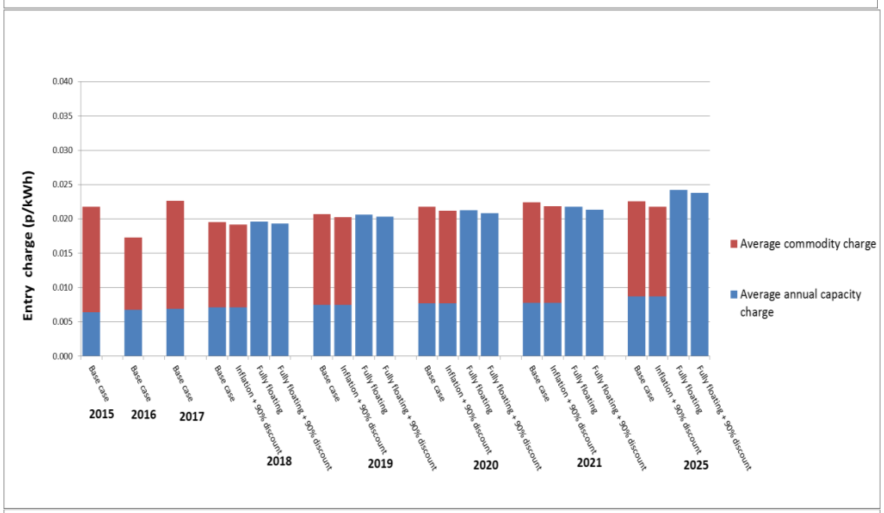
[34] Within the model, these charges were calculated based on the assumptions that flows=bookings.

Figure 12: Long-term bookings – entry cost

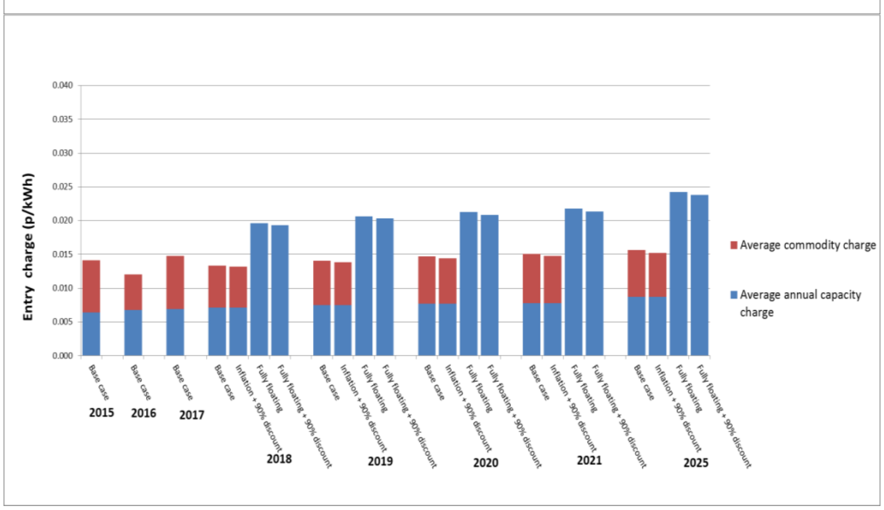
Flows = 100% of bookings



Flows = 60% of bookings



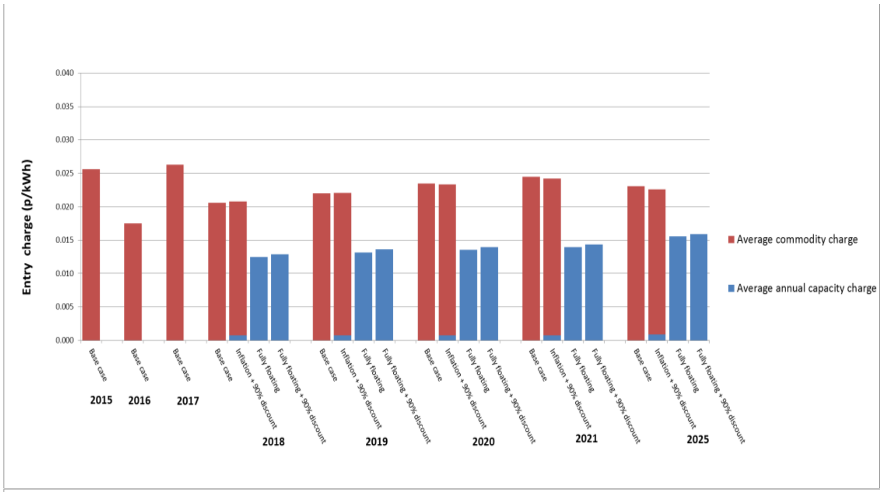
Flows = 30% of bookings



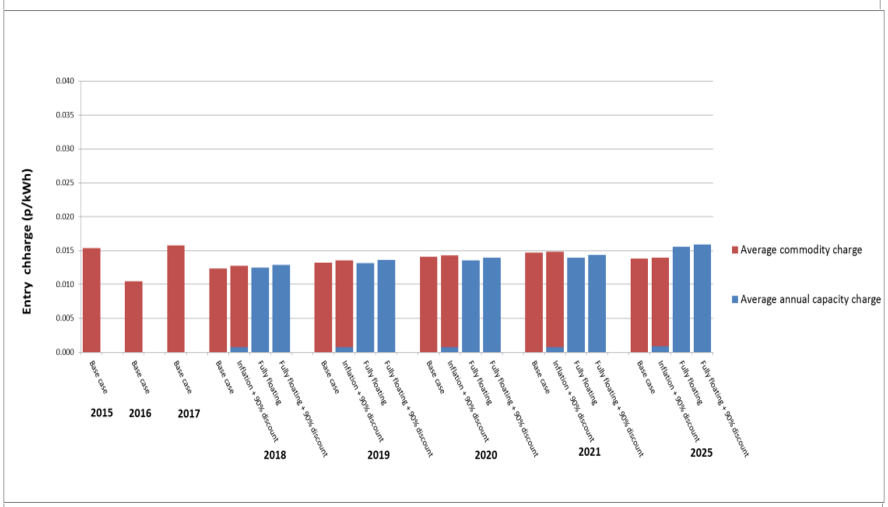
Source: Ofgem analysis based on CEPA/TPA Solutions model

Figure 13: Short-term bookings – entry cost

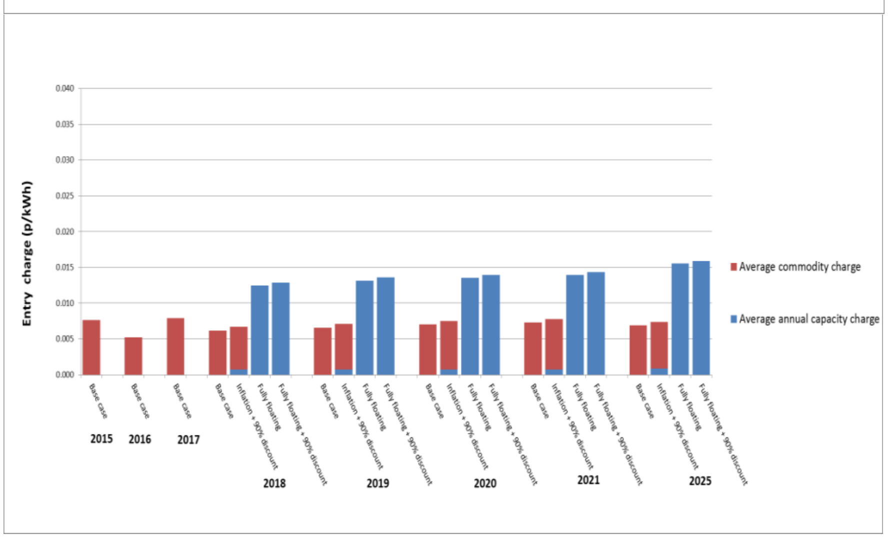
Flows = 100% of bookings



Flows = 60% of bookings



Flows = 30% of bookings



Source: Ofgem analysis based on CEPA/TPA Solutions model

Locational effects

3.38. In all policy options modelled, the existing LRMC methodology is used in the first stages of calculation of reserve capacity prices. The floating adjustment constant will be added to create final reserve prices. This means that, for long-term capacity, the same locational differences would remain.

3.39. Short-term capacity users will see a change. Currently, if they buy within-day or interruptible capacity, their capacity charge is zero at all entry points on the network. Without 100% discounts, the new reference price for short-term capacity would increase from zero to an amount proportional to the relevant LRMC at an individual entry point[35]. This means, users would be affected differently, depending on their chosen location.

3.40. This policy change would apply equally to all network users, including storage.

Distributional impact – network user groups

3.41. The total amount of allowed revenue to be recovered remains the same under all policy options, while the distribution of charges across users may change. To understand better potential distributional effects across various groups of network users, we have looked at how allowed revenue is recovered by:

- type of user, according to supply source; and
- type of capacity booking – short-term/long-term.

Type of user – by supply source

3.42. The model uses the NGGT long-term planning scenarios (FES and the Gas Ten Year Statement) as the source for assumptions in the daily and annual supply dispatch modelling. Annual demand assumptions are consistent with the selected planning scenario, but the supply mix used to balance supply and demand is then determined within the model. The approach taken to model daily flows by supply source is shown in Figure 14 and described further in the CEPA/TPA Solutions report, published on our GTCR website.

3.43. There are 5 types of supply sources in the model -

i. UKCS (excluding Easington flows)

ii. LNG

[35] The floating component would be the same for everyone.

iii. Storage (including Rough)

iv. Easington (Norway and UKCS flows)

v. Continental imports (referred to as IC (interconnector flows) or CAM)

Figure 14: flow dispatch modelling methodology

1) Take wholesale traded price input projections for each gas day and each year in the impact assessment

2) Determine – under modelled tariff policy options – the cross-border flows of interconnectors

3) Determine storage flows for the gas year – import and export to the National Transmission System

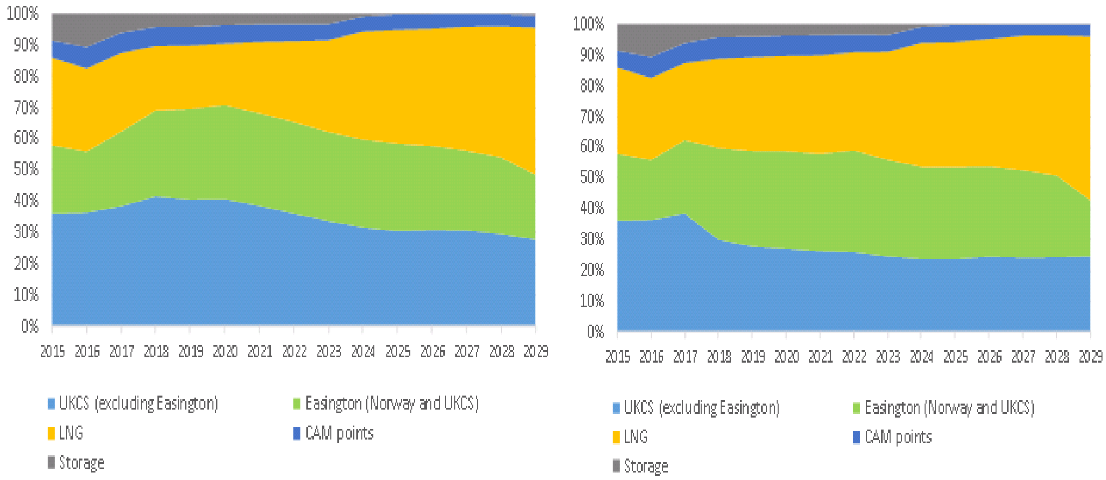
4) Determine profiled beach supplies from UK Continental Shelf and Norway supply sources

5) Determine required LNG supplies to match supply with demand on each gas day

Source: CEPA/TPA Solutions

3.44. The trends in revenue recovery by supply source (Figure 15 overleaf) largely follow the chosen Future Energy Scenarios, with the structure of entry charges having a marginal effect. Under fully-floating options, compared with the base case, revenue recovery is slightly lower for UKCS (excluding Easington) and slightly higher for Easington (Norway and UKCS) and LNG.

Figure 15: Revenue recovery by user group a) under the base case (90% short-term discount) b) with fully-floating charges (90% short-term discount)



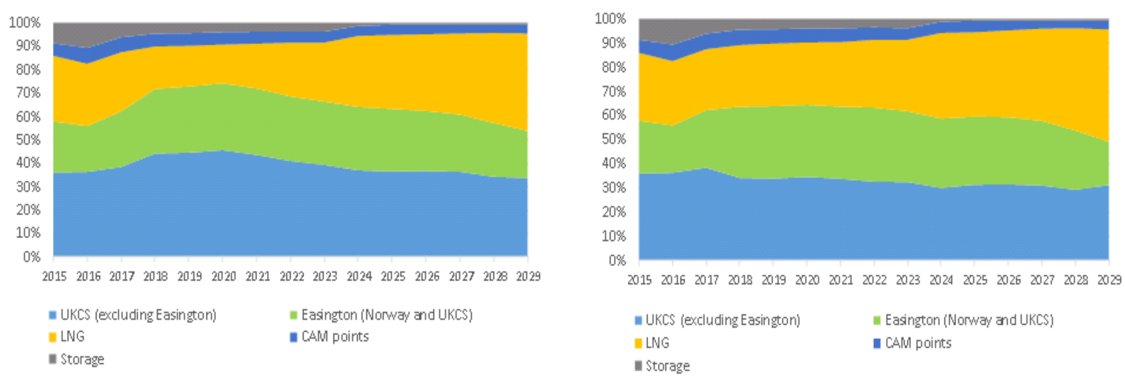
Source: CEPA/TPA Solutions model

3.45. Under both regimes – commodity charge and fully-floating – the level of short-term discounts marginally changes the revenue recovery by supply source. With lower discounts, more revenue is recovered from UKCS, and less from LNG (see Figure 16 below). We think this is due to:

- on average, higher LRMCs for the UKCS entry points (eg in 2021 St Fergus LRMC is 0.0458 pence/kWh compared to 0.0214 pence/kWh for Milford Haven), which means lower discounts have a stronger impact; and

- booking behaviour by UKCS and LNG users, with the former possibly relying more on short-term capacity.

Figure 16: Revenue recovery by user group a) under the base case (30% short-term discount) b) with fully-floating charges (30% short-term discount)



Source: CEPA/TPA Solutions model

3.46. Storage don't pay commodity charges, and would not be paying the floating adjustment – therefore revenue recovery from these users illustrated in Figure 16 appears relatively small. However, storage users would have paid entry and exit capacity and commodity charges on entering/existing the NTS, so their contribution is captured implicitly in revenue recovery attributed to other sources.

Type of booking – short-term/long-term

3.47. The trend for greater short-term bookings persists irrespective of charging regimes, except when short-term products become more expensive than long-term products. When we modelled a short-term capacity premium of 120%, the short-term bookings fell sharply to 1-3% of the total bookings for the whole period (see Appendix 6, Figure A6-4).

3.48. With all other policy options, the percentage of short-term bookings gradually increases from around 20% of the total in 2015 to 30% in 2021 and 45% in 2029. The breakdown of short-term bookings by product also remains stable.

- Day-ahead: 1 % of total short-term bookings;
- Within-day: 43%, increasing to 45% in later years;
- Interruptible: 45%, increasing to 48% in later years; and
- Monthly: 10%, decreasing to 8% in later years.[36]

3.49. This suggests that as long as short-term capacity is priced at a lower level than long-term capacity, the demand for short-term capacity is not responsive to price (capacity charge) changes. This may be explained by the users' expectation of continuing availability of spare capacity on the network, as well as the value they place on the flexibility provided by the short-term products.

3.50. We also analysed the contribution of short-term and long-term capacity users make to revenue recovery (Figure 17). As short-term capacity becomes more expensive, up to the point where it is priced at the same level as long-term capacity, the revenue from short-term bookings increases. Again, this supports the earlier conclusion about low price responsiveness of short-term bookings.

3.51. Under the fully-floating arrangements, with high short-term discounts (existing rates/90%), the contribution to revenue recovery from short-term users is around 50% of the total. This increases to around 55% when short-term capacity is priced the same as long-term, or the discount is low (30%).

[36] The same pattern of short-term booking behaviour is observed since 2010 in real NGGT's bookings data.

3.52. For the commodity charge regime options, the contribution to revenue recovery is through a) capacity charge revenue and b) commodity charge revenue:

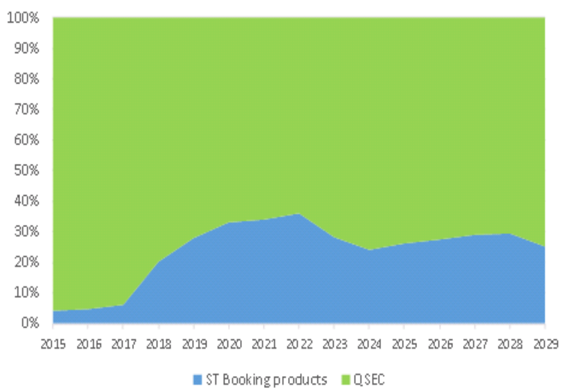
- With high short-term discounts – the existing 100% rate or 90%, the contribution to revenue recovery from short-term users is around 10% or 30% of the total, respectively. The contribution through the commodity charge is proportional to the share of short-term flows of the total flows. In the model, flows are equal to bookings, so the relevant contribution is 20% of the total in 2015, rising steadily to 30% in 2021 and 45% in 2029.

- The contribution to revenue recovery from short-term products increases to around 70% when short-term capacity is priced the same as long-term, or the discount is low (30%). The commodity revenue contribution is as described above.

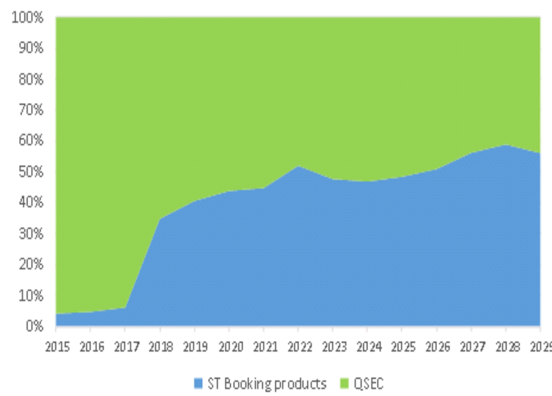
Figure 17: Revenue recovery by short-term/long-term capacity products

High discount (90%)

Base case



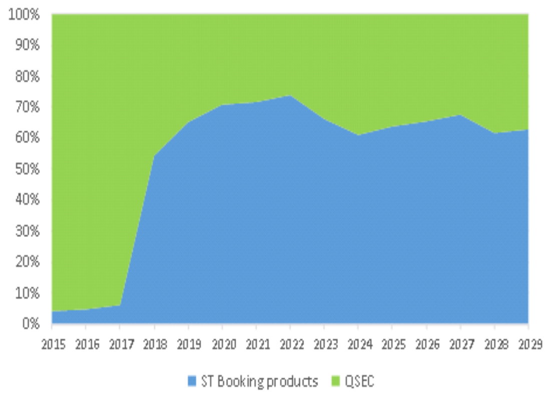
Fully-floating

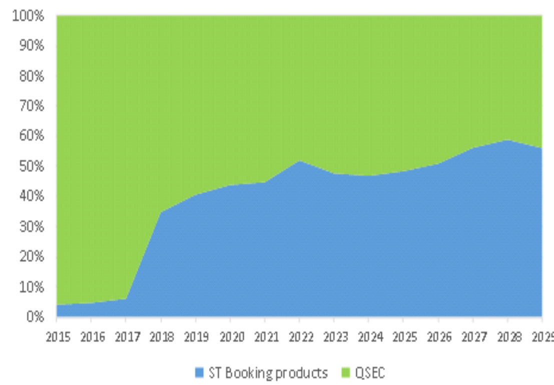


Low discount (30%)

Base case

Fully-floating





Source: CEPA/TPA Solutions model

3.53. In summary, under fully-floating arrangements, the contribution to revenue recovery by users of short/long-term capacity is broadly in line with short/long-term capacity bookings. The modelling results suggest that the size of the discount doesn't dramatically affect this. Under the commodity charge options, it appears that the size of the discount plays a stronger part: as discounts become less generous, short-term capacity revenue contributions increase more substantially. However, as the commodity charge increases, and the commodity revenue becomes the dominant component of revenue recovery, the contribution of different users will be determined largely by their flow choices.

3.54. As discussed above, the modelling results should be interpreted as indicative. For example, the conclusion that the demand for short-term capacity is relatively inelastic (until the short-term price exceeds long-term) seems sensible. However, in reality, the size of the discount may have a more nuanced effect on shipper behaviour than the simple linear one suggested by the modelling.

Sensitivity analysis

Future Energy Scenarios (FES)

3.55. The GTCR model uses the National Grid's long term planning scenarios (FES and the Gas Ten Year Statement) only as a source for assumptions in the daily and annual supply dispatch modelling.[37] That is, annual gas demand is consistent with the selected planning scenario (eg Gone Green), and total gas supply is set to match

[37] http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Gas-Ten-Year-Statement/

it. The *actual* supply mix used to balance supply and demand is determined *within* the model. For example, there are a series of modelling steps to determine dispatch from flexible supply sources such as cross-border flows and storage. On the other hand, modelling of UKCS flows is more straightforward – annual totals are selected from the Gas Ten Year Statement, and split by entry point according to the proportion of historical supplies for 2012/13. The LNG flows are simply set to meet the residual demand in the model once all the other sources of supply have responded.

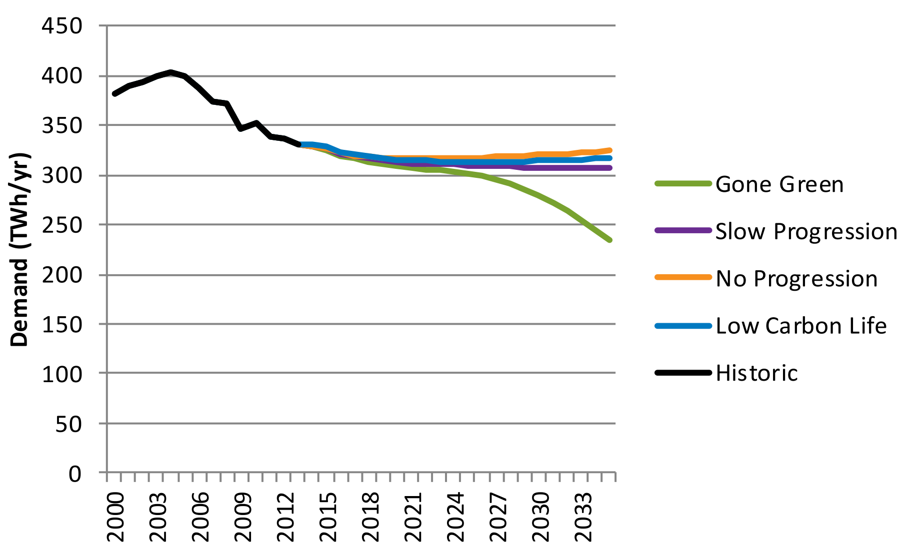
3.56. This approach has two effects on the results of the model:

- The resulting supply mix broadly follows FES scenario, but is ultimately unique to the model and its assumption. Supply modelling was discussed at length at the GTCR technical group, and it was recognised that the uncertainty of future supply and demand structure in GB beyond 2015 makes modelling challenging.[38]

- The results of the model are not materially influenced by the choice of FES, because the key parameter used in the model – gas demand – does not vary significantly over the modelled period (see Figure 18 below).

3.57. For completeness, we present the results of our sensitivity analysis for the Gone Green scenario, as it gives the most divergent results relative to the Slow Progression used in the model.

Figure 18: GB gas demand (FES 2014)



Source: National Grid FES 2014

[38] For example, the model doesn't include shale gas. The technical group's report mentioned the relatively static supply mix assumption as one of the limitations of the model.

FES: flows

3.58. The charts below show the changes in the flows for different supply sources for Gone Green scenario, relative to Slow Progression scenario. The first chart shows changes in the absolute flows while the second chart shows percentage point changes in the proportion of total flows.

3.59. You will note that storage flows are not directly included in these charts as a supply source. The model works on an annual basis, and assumes that over the course of the year net storage flows are zero – that is, the gas entering storage empties out again, as demand is met.

3.60. Both charts show that for each of the four flow sources, the different FES scenarios have a relatively uniform impact regardless of the policy option selected. The most pronounced differences for the same flow type are both under the fully-floating scenario:

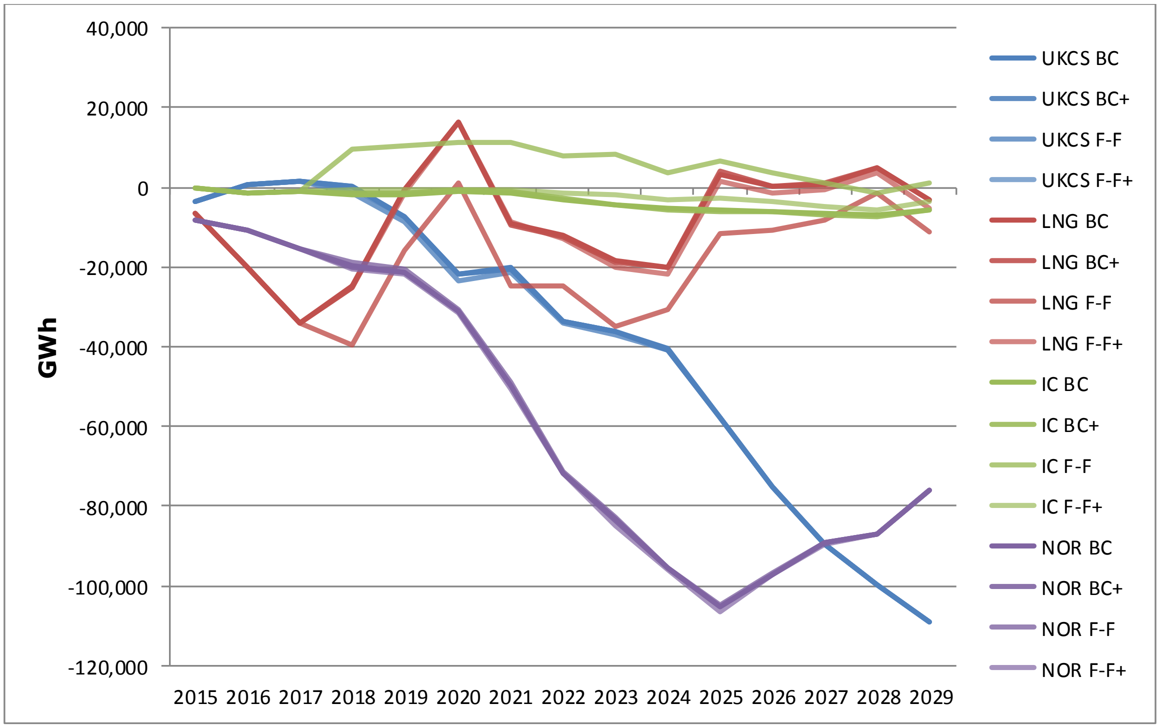
- the LNG flows, which show the biggest decrease for Gone Green relative to Slow Progression;
- in contrast, the interconnector flows show the biggest increase for Gone Green relative to Slow Progression.

3.61. Generally, Gone Green results in an absolute decrease in all flows apart from interconnector flows. The biggest reductions are for UKCS and Norway. Gone Green also sees Norway account for a lower proportion of total flows, with UKCS only accounting for a smaller share than the beginning of the period in the mid-2020s. LNG flows account for a steadily increasing proportion of flows under Gone Green, while interconnector flows are relatively stable.

Key to charts:

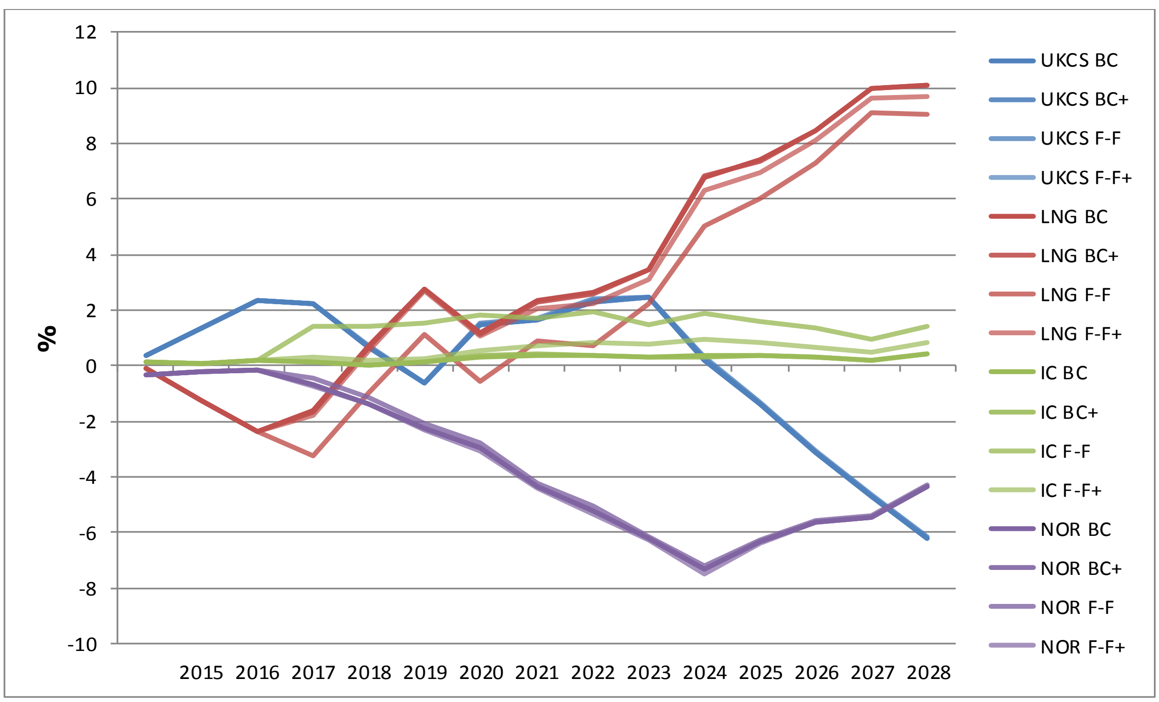
- Supply sources: UKCS, LNG, Norway (NOR), interconnector flows (IC).
- Charging options: Base Case (BC), fully-floating (F-F), Base Case with 90% discounts for short-term capacity (BC+), fully-floating (F-F), fully-floating with 90% discounts for short-term capacity (F-F+).

Figure 19: Flows by supply source, Gone Green relative to Slow Progression – absolute difference in GWh



Source: CEPA/TPA Solutions model

Figure 20: Flows by supply source, Gone Green relative to Slow Progression – difference in percentages



Source: CEPA/TPA solutions model

FES: revenue recovery

3.62. Both charts show the changes in the revenue recovery for different sources from the Slow Progression to the Gone Green FES. The charts include storage. The upper chart shows changes in the absolute revenue recovery while the lower chart shows percentage point changes in the proportion of revenue recovery.

3.63. As with flows, both charts show that for each of the six revenue sources, the different FES scenarios have a relatively uniform impact regardless of the policy option selected. The most pronounced difference is for the Easington Base Case where revenue recovery is far higher than for the other policy options until the final years of the period.

3.64. The other notable differences are a split between the two base case options and the two fully-floating options for UKCS. Under the base case options, UKCS revenue recovery is more volatile than for the fully-floating options but approach a similar level from 2026 onwards.

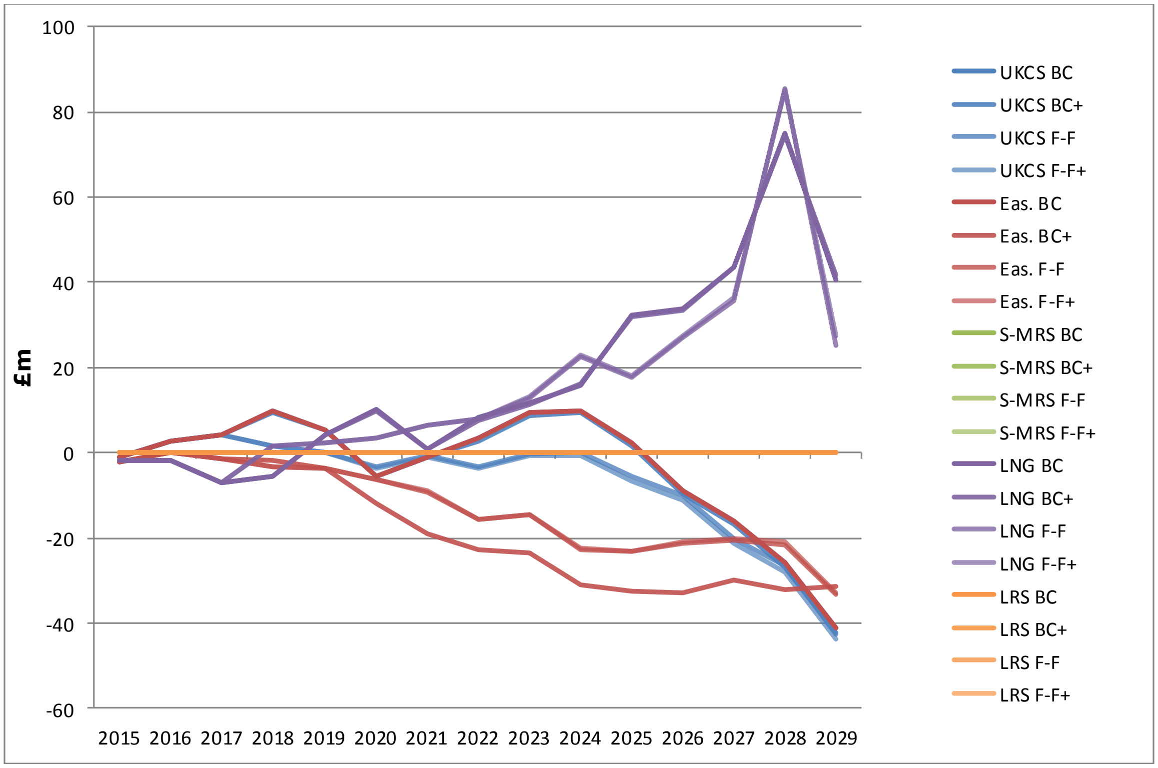
3.65. Generally, Gone Green results in an absolute decrease in all revenue recovery from UKCS and Easington, but an increase for LNG. All other sources remain relatively stable. A similar pattern emerges in the proportion of revenue recovery that each source accounts for.

Key to charts:

- Supply sources: UKCS, LNG, Norway (NOR), interconnector flows (IC), short-medium range storage (S-MRS), long-range storage (LRS).

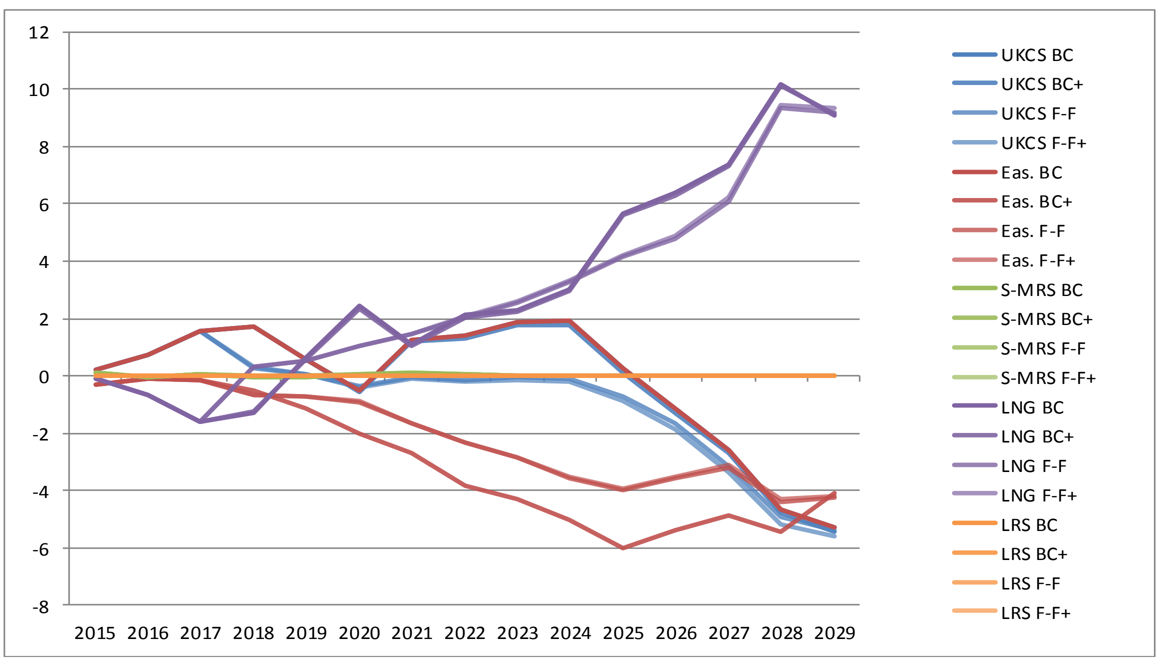
- Charging options: Base Case (BC), fully-floating (F-F), Base Case with 90% discounts for short-term capacity (BC+), fully-floating (F-F), fully-floating with 90% discounts for short-term capacity (F-F+).

Figure 21: Revenue recovery by supply source, Gone Green relative to Slow Progression – absolute difference in £m



Source: CEPA/TPA Solutions model

Figure 22: Revenue recovery by supply source, Gone Green relative to Slow Progression - difference in percentages



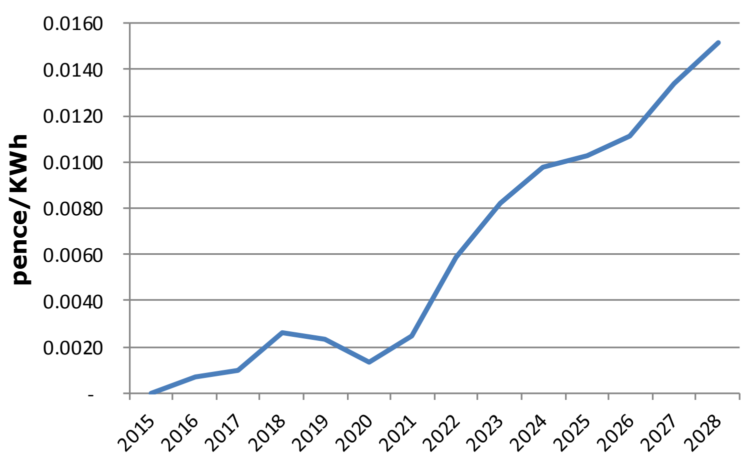
Source: CEPA/TPA solutions model

FES: entry charges

3.66. Under all policy options, the main difference in the level of charges between the Gone Green and Slow Progression scenarios comes from the socialised charging component (ie commodity charge or floating adjustment). This is not surprising, as demand for gas under Gone Green is lower, which in turn means less gas needs to be transported on the NTS, and less NTS capacity is bought. In our model, we make a simplifying assumption that NGGT's allowed revenue is set to increase at the rate of inflation, irrespective of trends in gas demand. This increases the gap between the allowed and recovered revenue, increasing the commodity charge/floating adjustment.

3.67. There are no changes in capacity charges between the FES for the commodity-based regimes (irrespective of the level of short-term discounts). The commodity charge steadily increases under the Gone Green scenario relative to Slow Progression.

Figure 23: TO commodity charge - Gone Green relative to Slow Progression

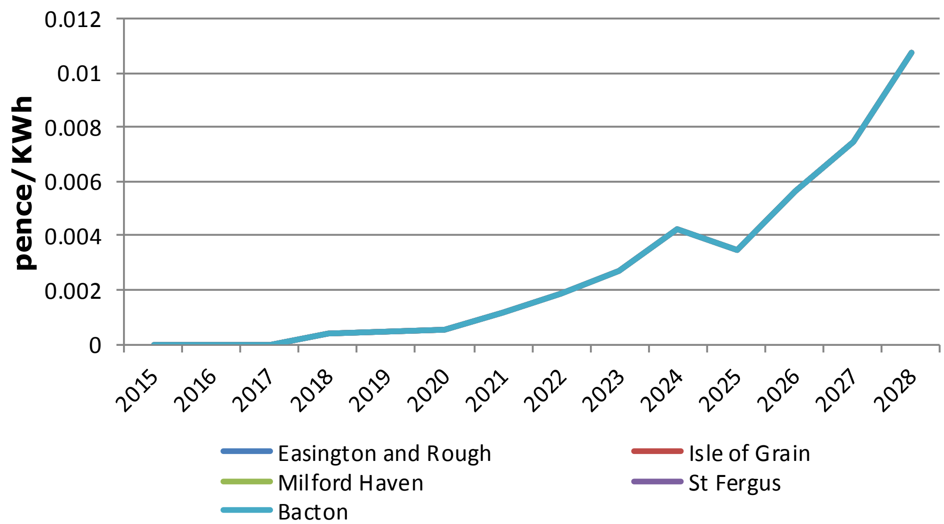


Source: CEPA/TPA Solutions model

3.68. The effect of the FES on the capacity charge under fully-floating arrangements is consistent across all entry points. Fully-floating capacity charges continue to increase over time under Gone Green compared with Slow Progression (irrespective of the level of short-term discounts).

3.69. The difference is constant across all entry points, because the variance comes from the floating adjustment component of the charge. This is similar to the trend in the commodity charge, illustrated above.

Figure 24: Fully-floating capacity charges, Gone Green relative to Slow Progression



Source: CEPA/TPA Solutions model

Storage charges

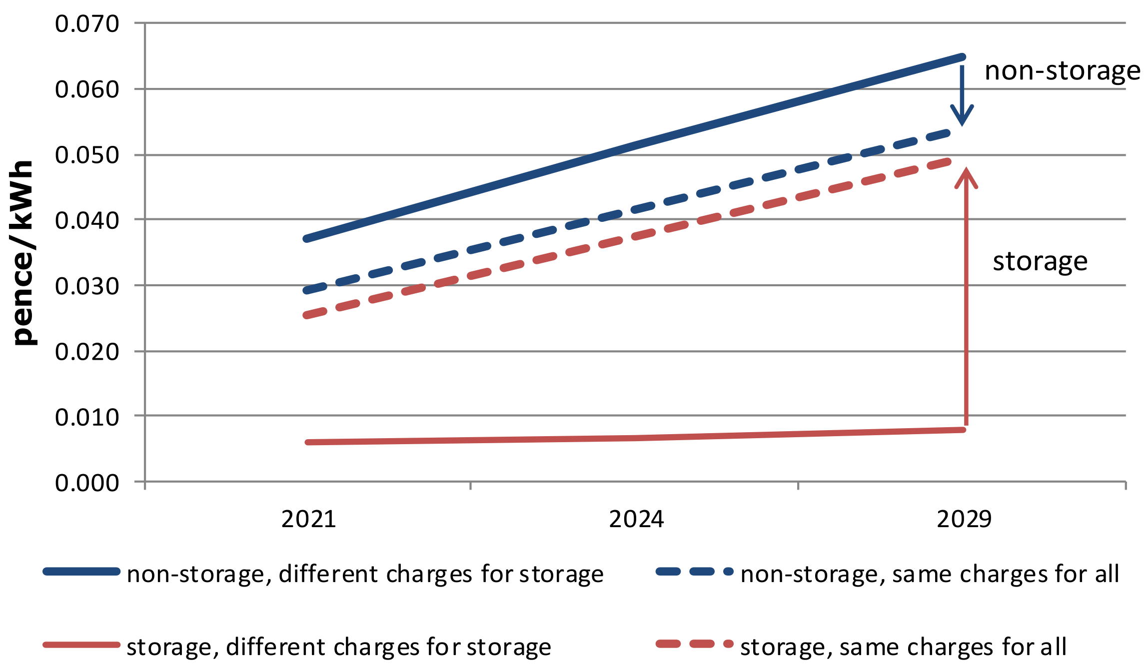
3.70. Under our proposals the 'floating' element of the charge would not be applied to storage users. Subject to consultation responded, we intend to preserve the existing arrangements, where storage users don't pay the top-up element (currently commodity charges). For completeness, we have modelled scenarios of the fully-floating regime where storage users would be treated the same as non-storage users – that is, they pay the floating adjustment.

3.71. The chart below presents the results for fully-floating capacity charges, in a regime with 90% short-term discounts. The results are almost identical for the scenario with the existing discounts.

3.72. Storage charges increase dramatically when the floating adjustment is included. The rate of the increase grows over time, as the amount of revenue to be recovered through the socialised component rises[39]. Charges at non-storage entry points would reduce as a result, but the decrease would be less significant than charge increases at storage points.

[39] This is largely driven by the assumption that the allowed revenue remains constant at 09/10 prices (ie charges will increase in line with inflation), and the demand for capacity remains constant.

Figure 25: Entry charges with same/different charging arrangements for storage users



Source: CEPA/TPA Solutions model

Qualitative assessment

3.73. We have discussed the shortcomings and benefits of different charging arrangements in the preceding chapters. In summary, we think that the combination of fully-floating capacity charges and less generous short-term discounts would improve the efficiency of network use and promote efficient investment by NGGT, as well as facilitate security of supply. All of this benefits consumers over time.

Impact on cross-border trade

3.74. Changes to entry charges could potentially have an effect on cross-border trade. Users have the choice to enter gas onto the GB system via interconnectors with the Belgian and Dutch markets. The driving factor for wholesale trade of gas between GB and continental Europe is the difference between the prices of gas at the GB, Belgian and Dutch hubs (NBP, ZEE and TTF). As the hubs become more liquid, these price differentials should reduce (provided there are no other barriers to trade – eg lack of interconnecting infrastructure, significantly different regulatory regimes, etc.). This means that transaction costs – including transmission entry charges – can affect the arbitrage opportunities, and increasingly influence cross-border trade.

3.75. Any entry charge will have the potential to influence a shipper's decision to move gas between markets. That is because it will change the *effective* price difference between those markets, reducing the potential earnings from arbitrage compared with a charge-free system. The structure of charges may have an effect on incentives for cross-border trade, as well as the absolute level.

3.76. Our modelling results suggest that where users don't book capacity significantly in excess of their flows, their costs of entering the NTS should be lower under the fully-floating arrangements, compared to the current regime. This suggests that transaction costs associated with cross-border trade of gas are likely to be lower under the fully-floating charges. This should help to better facilitate trade in gas, and support security of gas supply in GB.

Wider impacts

3.77. We think the impact of our proposals is mostly confined to those directly involved in gas shipping transactions. We haven't identified any substantial spill-over impacts on sustainable development (eg managing the transition to a low carbon economy, eradicating fuel poverty and protecting vulnerable consumers) or health and safety.

3.78. Some industry stakeholders commented that our proposals would affect third-party (ie non-NGGT investment). The Gas Forum report suggested we consider the impact of our proposals in the following areas:

i. *"Possible impacts on future investment in "marginal projects" and the knock on effects for overall security of supply. For example, would a new charging structure be detrimental to the development of new gas storage capacity?"*

ii. *"Overall impacts on system utilisation. Could a charging structure deter lower value users from utilising the network, thereby exacerbating revenue under-recoveries?"*

iii. *"Over-investment or gold-plating of the network. Would a change in charging structure lead to an over-booking of longer term capacity products, falsely signalling a demand for additional capacity?"*

3.79. On (i), any effects on prices faced by users of existing entry facilities would apply to users of new facilities equally. We have considered above the potential effects of changes on cross-border trade, and these effects would apply to the case for new interconnectors or new LNG entry points as for existing ones. As noted, our analysis suggests that a fully-floating charging regime would have less effect on incentives to bring gas into the UK from other markets than the current regime. We are not proposing to make significant changes to the charges faced by storage users. Storage users will face slightly increased costs for short-term capacity products if discounts are reduced. However we have not to date seen evidence that this would materially affect the case for new storage capacity. We would be grateful for any evidence that stakeholders wish to provide on these questions, in relation to our proposals.

3.80. On (ii), we have modelled effects on a population of users that is effectively the same as the current population, in terms of likely response to incentives including prices. It is not possible to model effects on all potential users, including those whose value from bringing gas onto the GB network is not sufficient, under the current regime, for them to enter the market. However we do not think that our changes will affect the earnings from shipping gas disproportionately for any identified type of user, so we do not currently believe that a group of users would be deterred from using the network under out changes. We would be grateful for any evidence from stakeholders, particularly users who consider that they would be so affected by the changes we are proposing.

3.81. In relation to these questions, as well as on others, we are happy to receive confidential responses.

3.82. We think that (iii) is unlikely to occur. The arrangements for users to secure incremental gas capacity will change with the introduction of Planning and Advanced Reservation of Capacity Agreements (PARCAs).[40] PARCAs remove the sale of incremental capacity from the QSEC auction.[41] Instead, users will be required to signal for incremental capacity by signing a PARCA with NGGT. Users will need to request sufficient amounts of capacity[42] and go through a multi stage process with phased financial commitments and the requirement to provide demonstration information in order to secure incremental capacity. This process has been developed to minimise the risk of spurious or false signals for NTS investment.

[40] The Authority published licence changes and approved UNC modification 465V on 8 December 2014 to introduce PARCAs. Changes to NGGT's gas capacity methodology statements are expected to be made in Q1 2015 which will fully implement the PARCA arrangements.
[41] This refers to Funded Incremental Obligated Capacity. NGGT can still release Non-obligated Entry Capacity at the QSEC auction.
[42] NGGT will apply the NPV test when determining if obligated incremental capacity should be released.

4. Assessment against our objectives

Chapter Summary

This chapter sets out our assessment of the proposed changes against our principal objective and relevant statutory duties. We take into consideration the conclusions from the quantitative and qualitative assessment set out in the preceding chapter.

Question box

Question 1: Do you agree with our assessment of how our changes would align with our principal objective and statutory duties?

Question 2: Can you provide any evidence that supports or would contradict our assessment against one or more of them?

Question 3: Do you think there are other duties or aims that we should assess these changes against? If so, what are your views on how our changes might affect them?

Overview

4.1. Our principal objective under the Gas Act 1986 is to protect the interests of existing and future gas consumers. We need to consider whether the proposed changes further the achievement of this objective and are consistent with our statutory duties, including the duty to ensure compliance with European law.

4.2. The design of network access charges is relevant to our principal objective and duties. It provides incentives for industry participants, driving their decision making and behaviour, which have the potential to affect consumer bills.

4.3. In assessing our proposals for gas transmission entry charges against our duties, we have considered the following:

- consumer bill impact;
- security of supply;
- promoting competition;
- best regulatory practice; and

- compliance with European law.

4.4. In line with our duties, we also set out more focused criteria for assessing different charging regimes at the start of the GTCR:

- economic efficiency in both the short run and the long run;
- impact on cross-border trade; and
- reflection of developments in the transportation business.

Consumer bill impacts

4.5. Transmission entry charges amount to around 3% of the average consumer bill. Our proposed policy changes will not increase nor decrease that proportion significantly. We expect the benefit to consumers will be dynamic: potentially avoiding future bill increases by improving the efficiency of NGGT's network investment, and helping to ensure that GB security of supply, including cross-border trade in gas, is not restricted by network access charges.

Security of supply

4.6. Our modelling suggests that fully-floating capacity charges may result in lower transaction costs for cross-border trade in gas, compared to commodity-based regimes. This can help to better facilitate the security of gas supply.

4.7. Under our proposals the 'floating' element of the capacity charge would not be applied to storage users. We intend to preserve the existing arrangements, where storage users don't pay the top-up element (currently the commodity charge). This means that the role of storage is maintained in the supply mix.

4.8. Overall, we consider that our proposals would not materially affect GB security of supply overall.

Promoting competition

4.9. We consider that our proposals are likely to further competition. This is because fully-floating capacity charges and lower discounts for short-term capacity improve the cost-reflectivity of entry charges.

4.10. The burden of charges will shift amongst different network users. However, our analysis suggests that while the distributional effects are not uniform, they are not acutely detrimental nor distinctly beneficial to any particular type of user. We do not think the distributional impacts will have an adverse impact on competition between network users.

4.11. The impact of our proposed changes on competition is discussed in more detail later in this chapter (4.214.20 - 4.28).

Best regulatory practice

4.12. We are required to have regard to better regulation principles in making decisions. For the reasons set out above, we think our proposed changes further the interests of existing and future consumers.

4.13. We also think they are proportionate, taking into account their expected distributional effects, given the overall aim of improving cost reflectivity, promoting greater efficiency of network use and investment, and the resulting overall ongoing benefits to consumers.

4.14. As noted earlier in Chapter 1, we have been open and transparent in our policy making process, and engaged with the relevant stakeholders through the review. This consultation is another important opportunity for all interested parties to present convincing evidence which we will consider in arriving at our final policy position.

4.15. Taking account of the importance of stability and predictability in regulation, Chapter 6 sets out our next steps, and further opportunities for you to tell us what you think.

Compliance with European law

4.16. 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 sets out non-discriminatory rules for access conditions to the natural gas transmission networks. This is to ensure the proper functioning of the internal market in gas. The Regulation provides the legal basis for the adoption of a legally-binding network code on the EU-wide harmonised transmission charge structures for gas (TAR NC).

4.17. We consider that our policy proposals meet the criteria set out in the Regulation, including contributing to market integration, enhancing security of supply, promoting competition and cross-border trade, and ensuring cost-reflective transmission charges.

4.18. The move to fully-floating capacity charges would bring GB closer to the prevailing network charging approach in the rest of the EU. It should, however, be noted that the floating adjustment method set out in our consultation is meant to convey the spirit of the policy – that is, a move to capacity-based charges. The exact method for calculating the fully-floating charges will be discussed and debated with NGGT and the industry, and will need to comply with the Regulation and, where relevant, to deliver compliant implementation of TAR NC into the GB regime (more on implementation in Chapter 6).

Economic efficiency in the short run and the long run

4.19. The main areas for assessment under this criterion are competition and the efficiency of the network operation and investment.

Competition

4.20. We think that entry charges could potentially affect competition between network users, depending on:

- how cost reflective they are; and
- what distributional effects they produce.

4.21. The principle of cost-reflectivity is based on the economic rationale that, in general, competition is more likely to be effective if costs which parties impose on the system are reflected in the charges they pay, and therefore are appropriately factored into their commercial decisions.

4.22. To the extent that our proposals promote cost-reflectivity in charges, we must consider whether the competition benefits are outweighed by any detriments – such as significant redistribution effects or increased complexity.

Cost-reflectivity

4.23. We consider that our proposals would lead to more cost-reflective entry charges, compared with alternative regimes where commodity charges are retained to adjust for under-recovery of revenues. We think that the main improvements are in:

- Allocation of historical costs. The move to fully-floating capacity based charges will help ensure that all users who benefit from access to a safe, reliable, flexible gas transmission network contribute to the recovery of past investment costs.
- Locational signals for short-term capacity users. Improving the ability of NGGT to signal the most cost-effective use of the NTS would help ensure that the network service is provided at value for money to existing and future consumers.

4.24. We think that these improvements, if implemented, would incentivise more efficient network capacity booking behaviour, and assist with efficient NGGT operational and investment decisions over the short and long run. We discuss this in more detail in 4.30 - 4.39 below.

Distributional effects

4.25. Changes to the charging methodology inevitably result in a redistribution of costs. As discussed in Chapter 3, the impact on individual users will vary according to:

- their level of contractual commitment:
    - proportion of QSEC bookings in their portfolio;
    - absolute size of QSEC bookings and length of the booked period.
- their flows as the proportion of their bookings; and
- for short-term capacity users, their choice of an entry point.

4.26. We have analysed NGGT's data on users' capacity holdings and flow patterns. We consider that the majority of users – given sufficient notice of implementation of changes – would be able to amend their behaviour and mitigate adverse effects. We also note that entry transportation charges remain a small proportion of the wholesale cost of gas. Our modelling suggests that under our proposals, in 2021, entry charges will account for a minimum of 0.6% of the wholesale gas price (at Hornsea), up to maximum of 3.15% (at St Fergus).

4.27. In our view, the redistribution of costs is not disproportionately high under our proposals and is appropriate in order to improve the cost reflectivity of charges.

4.28. In its report, the Gas Forum queried the impact of our proposals on new entrants, and those requiring access to short-term capacity or during off-peak periods. We consider that -

- Our proposals would limit the ability of the incumbent users to fix the cost of their booking commitments for future use at an artificially low level. This would safeguard new entrants from bearing a higher share of socialised historical investment cost. This would help lower barriers to entry.

- Our proposals would change the *price of access* to short-term capacity to encourage users to make more efficient commercial decisions, including locational choices. Our proposals would not affect the *availability* of short-term capacity in any way. The existing auction mechanism will continue to ensure efficient allocation in times of scarcity. Currently, arrangements are in place to ensure open access to capacity, including the ability for users to trade capacity and, in some circumstances, use it-or-lose-it arrangements to prevent capacity hoarding.[43]

- We don't think our proposals disproportionally affect users with capacity entitlements during off-peak periods.

Increased complexity

4.29. We don't think our proposals will by themselves increase the complexity of the GB gas transmission charging regime. The final design of the charging regime (ie the precise approach to calculating fully-floating charges, the level of short-term discounts) will be developed in discussion with NGGT and the industry, taking account of TAR NC provisions. We will bear in mind the risk to competition of increased complexity during those discussions.

Efficiency of network operation and investment

4.30. We consider that cost reflective charges allow market participants to make efficient commercial decisions about where to bring the gas onto the system, taking into account the wider costs of these decisions on the network. This assists in the planning and development of an economically efficient transmission system, which will benefit consumers over time in the form of lower bills.

4.31. In order to deliver this, we think it is important that the charging regime supports NGGT's operational and investment decision making process. This helps to ensure that the cost of delivering transmission services is not higher than it needs to be, which should benefit consumers.

Efficiency in the short run: network operation

4.32. We consider that our proposals would primarily better facilitate efficient network operation in the following ways:

- promoting better alignment of bookings to flows; and

- making the structure of short-term discounts more sustainable.

[43]NGGT is required to release capacity that has been sold but expected not to be used as an interruptible product – this mechanism is called Use-It-Or-Lose-It (UIOLI). The actual amount of UIOLI capacity that NGG must release is the average unused capacity (firm capacity sold minus the proportion of that capacity which is used to flow gas) over the previous 30 days. This is released at the day-ahead stage. UIOLI arrangements are set out in the UNC: Uniform Network Code – Transportation Principal Document Section B.

Better alignment of bookings to flows

4.33. A closer alignment of short-term capacity bookings and gas flows should improve economic efficiency by reducing the incentive to over-book that the current arrangements tend to produce. Operationally, the current low ratio of flows to bookings, with a high level of short-term bookings, means that total capacity bookings do not provide a sufficiently accurate source of information to help forecast supply patterns. This potentially leads to less effective operational decisions than would be possible if bookings are closer to intended and actual flows. .

Making the structure of short-term discounts more sustainable

4.34. On a pure economic argument, once a network has been built, the cost to NGGT of accommodating an additional user (called the short-run marginal cost or SRMC) is zero. However, as short-term capacity becomes the product of choice for large numbers of users, basing the level of discount and charges purely on the SRMC economic argument does not seem to us to take account of all of the relevant considerations.

4.35. First, as described above, ensuring that short-term users contribute to the recovery of past investment costs should lead to more accurate booking behaviour, which benefits the efficiency of network operation.

4.36. Second, providing a degree of locational signals for short-term capacity users, by removing 100% discounts should also improve operational efficiency. Locational signals - providing the capacity is being booked where it is needed - should lead to booking behaviour more in line with the most optimal network use solution from the network planning perspective. For example, locational signals could help incentivise network users to bring gas on at entry points closer to the demand centres. At the moment, 100% discounts (ie zero prices) mean there is no differentiation between entry points.

Efficiency in the long run: network investment

4.37. Capacity bookings are fundamental to both the release of incremental capacity and the substitution methodology and hence underpin the investment decision process. The lack of robust capacity booking signals increases the risk of inefficient investment – *in theory*, this could result in either under- or over-investment. *In practice,* the risk of under-investment may be higher, as the over-investment risk can be mitigated by the existing arrangements for the release of incremental capacity (eg the Net Present Value test), and will be further reduced once PARCAs are in force (see paragraph 3.79 above).

4.38. The long-term network investment decision making process is complex. Whilst the data on capacity bookings and flows is used, the ultimate decision requires consideration of much wider factors. These include future scenarios of supply and demand for gas, commercial information on likelihood and timing of third-party development projects (eg storage), as well as consideration of alternatives to physical investment (eg capacity management contractual solutions, substitution). There is also non-load related investment to consider, such as that required under the Industrial Emissions Directive. Depending on the combination of these considerations, the impact of charging arrangements on network investment could be less prominent, compared with that on operational efficiency discussed above.

4.39. We recognise that NGGT is obliged to comply with its wider licence obligations (ie baseline levels of capacity, pipeline security standards, etc), and not just take into account bookings and flows in its network analysis for the purposes of identifying investment needs. The NTS security standard, for example, is that the network must, taking into account operational measures, meet the 1-in-20 peak aggregate daily demand including within day gas flow variations.[44]

Impact on cross-border trade

4.40. We consider that our proposals help better facilitate cross-border trade in gas. This is discussed in detail in Chapter 3 (3.74-3.76).

Developments in transportation business

4.41. Current charging arrangements were introduced when the demand for network capacity was growing and:

- the network owner was over-recovering on its allowed revenue;
- we considered there was sufficient competition at the majority of beach terminals to avoid under-recovery; and
- we had concerns over the network owner releasing sufficient amounts of capacity to the market.

4.42. We now face a situation where:

- the network owner fails to recover its allowed revenue through capacity sales at auctions;
- there is spare capacity at the majority of entry points;
- there are low levels of competition for capacity in the short-term;

[44] The 1-in- 20 peak day condition and the pipeline security standards which NGGT has to use are described in more detail in its Transmission Planning Code, http://www2.nationalgrid.com/UK/Industry-information/Developing-our-network/Gas-Transportation-Transmission-Planning-Code/

- the network owner has firm baseline obligations to release capacity, as well as incentives to release capacity beyond these baselines; and
- system peak usage is significantly lower than these mandatory levels (just over 30% in winter 2013/14).

4.43. Our proposals retain the features of the regime which make it effective under the conditions of high demand – such as auctions. We are also proposing to keep the cost allocation methodology, including LRMC-based pricing.

4.44. We think our proposals improve the effectiveness of the regime under the conditions of sustained low demand for capacity, making it more robust and responsive to future challenges.

Risks and unintended consequences

4.45. We have not identified any risks or unintended consequences resulting from the proposed options beyond those already discussed elsewhere in this consultation.

4.46. We have engaged with industry stakeholders throughout the review to identify a comprehensive set of potential effects of our proposals. We would like to hear your views on any effects we may have missed, particularly any impact on Gas Distribution Networks.

5. Next steps

5.1. **Please provide feedback on our impact assessment and our initial policy view by 27 March 2015**.

5.2. Details on how to respond to this consultation, including contact details for any queries can be found in Appendix 1. This also gives a complete list of the questions on which we are specifically seeking respondents' views, although we welcome views on any aspect of this document.

5.3. We will hold an open forum for any questions and clarifications you may have regarding the initial assessment of impact set out in this document. This will take place on 25 February, at Ofgem. Please e-mail **Gas.TransmissionResponse@ofgem.gov.uk** to register.

5.4. We will consider all responses to this consultation before reaching a decision on the steps we will take after that. We will also take into account the content of the final Tariffs Network Code, and any steps needed to implement it. We will work with industry to identify what changes should be made to the GB regime, and when would be the best time for them to come into force.

Options for implementing changes to the charging regime

5.5. Our preferred approach to implementing the changes is to write to NGGT, asking it to raise a modification(s) to the Uniform Network Code (UNC), with our recommendations as to what the new charging regime should include.

5.6. There are alternative ways for the changes to be made:

- For changes required to ensure compliance with the TAR NC – but not other changes – we have the power to raise a UNC modification directly.

- We could consult on proposed amendments to NGGT's licence to require that the charging regime secured specific objectives.

- We could initiate a Significant Code Review (SCR). This would be a consultation on UNC provisions, at the end of which we might direct NGGT to raise a modification to the UNC. At present, we think the scope of our proposed changes is not wide enough to merit the additional cost, in industry engagement, of an SCR. However, this option remains available.

5.7. Each of these implementation options would require full consultation with industry and other stakeholders.

5.8. We think that the changes we are proposing would have benefits for GB consumers, for the reasons we set out in section 5. If, following responses to this consultation, we continue to think that the changes would improve outcomes for consumers, we will consider the best way of implementing them from the options above.

Implementation timing

5.9. We will also need to consider the timing of changes to the charging system. Since we think the proposed changes will have benefits for consumers, then the earlier they are made, the sooner consumers will benefit. However, we need to consider other relevant factors, including -

- The transitional costs across all of industry. These include the costs of engaging in discussions to develop reform proposals, responding to consultations, as well as investment in systems and/or training to be ready to work within the new system. While some of these costs are unavoidable, it can be more efficient to time changes together with other expected changes to the same aspects of the UNC – in this case, other charging changes. We also aim to avoid 'overloading' industry with concurrent major changes.

- Whether stakeholders can make changes to their behaviour which produce some of the benefits of the new system before it is implemented. For example, if a change affecting charges for long-term capacity is clearly signalled, and users are sufficiently confident that the change will happen, they may change their long-term booking strategy ahead of full implementation. This means that a delay in implementation for reasons of transitional cost efficiency would not delay all of the consumer benefits.

5.10. Depending on the final provisions of the TAR NC, the UNC and NGGT's charging methodology may need to be changed to be compliant. The implementation deadline for TAR NC by the Member States is currently set as: 1 October 2017, or 24 months from the date the Network Code enters into force, whichever is later.

5.11. If changes are needed to comply with the TAR NC, then we think it would be sensible to align the timing of changes resulting from this review with that timetable. This would avoid duplication of costs for industry in engaging with the consultation process, and in updating industry's internal systems to match the new charging regime.

5.12. If the current charging regime is compliant with the TAR NC without any changes being necessary, then there would be no particular advantage in timing the implementation of our proposed changes to TAR NC implementation date. We would seek a timetable for changes which was efficient in terms of the costs imposed on NGGT and industry, while providing benefits to consumers within a reasonable time.

Appendices

Index

Appendix 1 - Consultation Response and Questions

A1.1 Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

A1.2 We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

A1.3 Responses should be received by **27 March 2015** and should be sent to:

- Alena Fielding
- Gas Transmission
- Ofgem, 9 Millbank, SW1P 3GE
- Tel: 0203 263 2714
- Email: Gas.TransmissionResponse@ofgem.gov.uk, with a copy to alena.fielding@ofgem.gov.uk

A1.4 Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

A1.5 Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

A1.6 Any questions on this document should, in the first instance, be directed to:

- Alena Fielding
- Gas Transmission
- Ofgem, 9 Millbank, SW1P 3GE
- Tel: 0203 263 2714
- Email: alena.fielding@ofgem.gov.uk

<u>CHAPTER 1:</u> Gas Transmission Charging Review (GTCR)–background to our findings

No consultation questions

<u>CHAPTER 2:</u> Explanation of our proposed changes to the charging regime

<u>Question 1:</u> What are your views on our proposed changes?

<u>Question 2:</u> Do you agree with our rationale for rejecting the alternatives? If not, please explain why.

<u>CHAPTER 3:</u> Impact assessment of these proposals

<u>Question 1:</u> Do you think we have identified the relevant quantitative impacts?

<u>Question 2:</u> Do you think we have modelled the impacts appropriately?

<u>Question 3:</u> Do you think we have identified the relevant qualitative impacts?

<u>Question 4:</u> Do you have any further evidence of the potential impacts of our proposed changes not covered by our analysis?

<u>CHAPTER 4:</u> Assessment against our objectives

<u>Question 1:</u> Do you agree with our assessment of how our changes would align with our principal objective and statutory duties?

<u>Question 2:</u> Can you provide any evidence that supports or would contradict our assessment against one or more of them?

<u>Question 3:</u> Do you think there are other duties or aims that we should assess these changes against? If so, what are your views on how our changes might affect them?

<u>CHAPTER 5:</u> Next steps

No consultation questions

Appendix 2 – Introduction to GB charging regime

The role and importance of transmission charging

A2.1 Gas transmission charges are applied for using the gas transmission network (National Transmission System, NTS). The network is owned and operated by National Grid Gas Transmission plc (NGGT).

A2.2 Transmission charges allow NGGT to recover the cost incurred in providing the shared infrastructure needed to transport gas across the network. These charges are known as Transportation Owner (TO) capacity and commodity charges. They pay for the installation, reinforcement, maintenance and renewal of the shared transmission assets.

A2.3 As part of the RIIO-T1 price control, we have set the maximum amount of allowed revenue NGGT can collect through transmission charges over the eight years from 2013 to 2021.[45]

A2.4 NGGT is responsible for ensuring that appropriate gas transmission charging arrangements are in place.[46] Our role is to set out the principles that NGGT must adopt in carrying out this obligation, and to provide support and challenge to help it achieve this.

A2.5 The focus of this document is on transmission TO entry charging arrangements.[47]

Overview of the current gas transmission entry charging arrangements

A2.6 The current entry charging arrangements came into force in 2003, and have remained substantially unchanged since. At the time, demand for gas was growing, and a key policy objective was to maximise the availability of existing capacity to users and mitigate the risk of network congestion.

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[45] RIIO is Revenue = Incentives + Innovation + Outputs. RIIO-T1 is the first transmission price control review to reflect the new regulatory framework.
[46] NGGT has transmission licence obligations to have a transmission charging methodology in place, to keep its methodology under review at all times and to make proposals to modify that methodology where it considers a modification would better achieve the relevant objectives of the transmission charging methodology. The process for modifying the transmission charging methodology is contained within the Uniform Network Code (UNC), including when our decision is required.
[47] System Operator (SO) and shorthaul charges are not in the scope of this document.

A2.7 The GB entry charging regime has three main elements:

- auctions to allocate capacity to network users;
- capacity charges; and
- commodity charges.

Entry capacity: auctions

A2.8 In order to use the NTS, users must secure the right to flow gas. This means buying a sufficient amount of entry capacity for the amount of gas they wish to flow. NGGT sells entry capacity through a series of auctions. Auctions ensure that, where existing entry capacity is scarce, those users who value the capacity most get it.

A2.9 Entry capacity auctions span a range of time periods. Users can buy a guaranteed right to flow:

- 'long-term' capacity in 3 month blocks up to 17 years ahead (QSEC[48]) or monthly blocks up to 2 years ahead (MSEC[49]), as well as
- 'short-term' capacity the day before they wish to use it (DADSEC[50]) or on the day itself (WDDSEC[51]).

A2.10 Users can also buy interruptible capacity on the day of use (DISEC[52]) – where their right to flow may be curtailed by NGGT in the event of network constraints.

Entry capacity: capacity charges

A2.11 The auctions have a minimum, or reserve, price which the participating users must meet or exceed in order to secure the entry capacity they need. NGGT calculates these reserve prices based on the long run marginal cost (LRMC) methodology. The LRMC methodology assesses the impact of accommodating an additional unit of gas, at different entry points on the network, on transmission costs.

A2.12 The LRMC approach produces cost-reflective, locational reserve prices which send users price signals reflecting the economic costs of establishing and operating the network. These price signals are intended to enable users to make efficient

[48] QSEC – Quarterly System Entry Capacity auction
[49] MSEC - Monthly System Entry Capacity auction
[50] DADSEC - Day Ahead Daily System Entry Capacity auction
[51] WDDSEC - Within Day Daily System Entry Capacity auction
[52] DISEC - Daily Interruptible System Entry Capacity auction

commercial decisions about how to use the network, thereby assisting in the development of an economically efficient transmission system.

A2.13 NGGT offers discounted reserve prices at the auctions for daily capacity:

- Day-ahead (DADSEC) auction – 33.3% discount on the reserve price;
- Within-day (WDDSEC) auction – 100% discount on the reserve price i.e. a zero reserve price; and
- Interruptible daily (DISEC) auction - 100% discount on the reserve price, ie a zero reserve price.

A2.14 The rationale for the discounts comes from the economic theory of marginal cost pricing. This suggests that where the NTS infrastructure is already in place, the cost to NGGT of providing network capacity to any one additional user on any one day will be insignificant/zero.

A2.15 If the user's bid is successful, the price it bids becomes the 'capacity charge'. The user is liable for the capacity charge, irrespective of whether it uses the capacity to flow gas or not. The capacity charge is payable in the year in which the capacity is due to be used. The charge is 'pay as bid' – that is, not adjusted for inflation even if bought a number of years ahead of use.

Entry capacity: commodity charges

A2.16 Initial experiences of entry capacity auctions from 1998 to 2002 resulted in significant revenue over-recovery for NGGT. For example, in 2000, user bidding behaviour resulted in NGGT recovering 150% of its allowed revenue.[53] The weighted average prices as a percentage of reserve prices across all months were: 1030% at Bacton, 260% at Easington, 300% at St Fergus.

A2.17 Since 2002, entry auction revenues have increasingly resulted in under recovery in relation to NGGT's allowed revenue. The TO entry commodity charge was introduced in 2004 as a mechanism to correct for any under-recovery in NGGT's revenue following entry capacity auctions.[54] The commodity charge is a uniform, non-locational charge levied on the volume of gas a user flows.

[53] The over-recovery mechanism at the time was linked to constraint management and is too complex to summarise here. It was also undergoing change; please see Transco pricing consultation papers PC 65/66/67 over 2001.

[54] In the event of forecast revenue reaching the target level, or over-recovery, the TO commodity charge will be set to zero. The TO entry commodity rebate mechanism will be triggered (as set out in 3.2, Section Y of the UNCO. This mechanism will only be triggered if there remains a residual over-recovery amount after taking into account any revenue

A2.18 The cost to a user of bringing gas onto the NTS is the sum of[55]:

- Capacity charge (£pence/kwh): locational, pay-as-bid in the year of use, charged on the volume of capacity booked (irrespective of usage); and

- Commodity charge (£pence/kwh/day): non-locational, revised by NGGT in April and October each year, charged on the volume of gas flowed on the day.

Gas storage users

A2.19 Gas storage users don't pay the commodity charge. Storage gas circles around the system. It enters the NTS and exits to reach the storage facility; and then enters and exits the system again to meet demand. This means that gas going into storage has already paid an entry commodity charge, and will pay an exit commodity charge when it ultimately exits the system to meet demand. Storage gas has therefore made its contribution to historical cost recovery. Other EU member states also have special arrangements for storage users, including discounts in transportation charges, as well as direct subsidies (See Appendix 3 for a summary).

A2.20 The current transmission charging regime has served consumers well by promoting the efficient use of the transmission network and facilitating effective competition. However, as we discuss in the next chapter, a number of changes have happened. These have the potential to influence the suitability of the existing regime.

A2.21 The time is therefore right for us to consider whether the charging arrangements are fit for purpose, and set out our view on what changes, if any, may protect the interests of current and future consumers and ensure that our regime is compliant with the TAR NC.

redistributed by the buyback offset mechanism (defined in 2.3.2, Section Y of the UNC) and if this residual over-recovery is in excess of £1m.

[55] Network users will also be subject to System Operator (SO) entry charges. Subject to meeting certain criteria, users can also opt for a 'shorthaul' capacity product, which will attract 'shorthaul' charges instead of entry capacity and commodity changes. Only TO entry charges are considered in this document.

Appendix 3 – Storage in EU

Overview of transportation tariffs at EU storage facilities		
Member State	TSO	Tariff characteristics summarised
UK	National Grid Gas	Potential to use product with zero reserve price. Commodity charge only applied for gas used by the storage facility.
Germany	Open Grid Europe	Entry and Exit tariffs reduced by 50%
Germany	Thyssengas	Small reduction on entry, >33% reduction on exit
Belgium	Fluxys	No reduction on entry tariff, exit reduced by about 50%
Netherlands	GTS	25% reduction on entry and exit tariffs
Hungary	FGSZ	40% reduction on entry and 100% reduction on exit
Italy	SNAM Rete Gas	>60% reduction on entry and exit tariffs
Poland	Gaz-System	Up to 80% discount on fixed charges and 100% on variable
Portugal	REN	Entry tariff reduced by 97%
France	GRTGaz	More than 80% reduction on entry and exit
Croatia	Plinacro	90% reduction on entry, 100% on exit
Czech Republic	Net4gas	90% on commodity and up to 98% on exit
Spain	Enagas	Zero entry and zero exit tariffs

Source: ACER Initial Impact Assessment on Harmonised transmission tariff structures, updated in Waters Wye report on benefits of storage.

The table above must be read in the context of different treatment of storage across EU member states. Some European countries impose an obligation to keep a certain amount of gas in storage.[56] For example French legislation obliges suppliers to store at least 85% of the capacity rights for their domestic customers and those providing services of general interest (hospitals, schools) on 1 November. The Italian government regulates upper and lower bounds for storage obligations. In addition, some countries[57] regulate the access price to storage.

[56] Countries with a storage obligation: Bel, Bul, Den, Fr, Hun, Ita, Port, Slo, Sp. Countries with no storage obligation: Aut, Ger, Neth, UK.
[57] Aut, Hun, Ire (also negotiated access possible), Ita, Portugal, Latvia. Negotiated access price: Fr, Ger, Neth. GB has an exemption.

Appendix 4 - Modification Proposal NTS GCM 19 'Removal of NTS Daily Entry Capacity Reserve Price Discounts'

A4.1 In 2010 we received a proposal from NGGT to remove the discounts on the reserve price for the daily entry capacity auctions (both day-ahead and within-day). This was to make the reserve price for daily entry capacity auctions would be equal to the reserve price in the entry capacity monthly auctions. We rejected the proposal.

A4.2 At the time, we recognised the concerns NGGT identified with the level and volatility of TO entry commodity charges. However, we felt that the justification for the proposal, and the evidence presented were not sufficiently developed to give us the confidence that implementing this proposal would achieve the intended aims or bring about the behavioural changes that its supporters hoped for. For example, the impact of the changes on NGGT's revenue was presented as ranging from £3m to £71m, with an impact on the commodity charge being modest (decrease of 2 per cent) or significant (42 per cent).

A4.3 We also objected to moving away from the principle of short run marginal cost pricing. However, as discussed above, the trend in booking behaviour towards short-term products, and the adverse consequences for revenue recovery and efficiency of network use, means that a compromise is in the overall interest of consumers.

A4.4 Below are extracts from our decision letter on the GCM19 modification, published 30 July 2010. The full decision is available on our website:

https://www.ofgem.gov.uk/publications-and-updates/decision-letter-modification-proposal-national-transmission-system-nts-gcm-19-%E2%80%98removal-nts-daily-entry-capacity-reserve-price-discounts%E2%80%99

GCM19 proposal summary

The modification proposal GCM19 would remove the discounts on the reserve price for the daily entry capacity auctions (both day-ahead and within day) such that the reserve price for daily entry capacity auctions would be equal to the reserve price in the entry capacity monthly auctions.

Justification of the modification proposal presented by NGGT

NGG considers that GCM19 better achieves the relevant gas transmission transportation charging methodology objectives[58] in that:

- Cost reflectivity is improved: NGG argues that if daily entry auction reserve prices are discounted, and allowed revenues that are not collected from auctions are collected via the TO entry commodity charge, then the TO entry commodity charge may not be cost reflective. NGG argues that removal of the discounts via GCM19 would therefore improve cost reflectivity of TO entry commodity charges;
- Efficiency is promoted: NGG argues that removing short-term entry capacity discounts will incentivise greater procurement of long-term entry capacity, with the implication that a more appropriately sized NTS would be developed. NGG argues that discounted or zero short-term reserve prices are attractive when NTS entry capacity is perceived to be plentiful and so discourage long-term signals for new NTS entry capacity, but when entry capacity becomes scarce this can lead to unpredictable NTS entry capacity prices at auction and more frequent scale back of interruptible NTS entry capacity until incremental NTS entry capacity is signalled and provided;
- Undue preference is avoided: NGG argues that while those booking short-term NTS entry capacity receive discounts, and the shortfall in auction revenue is recovered by all users, then those booking in the short term are cross subsidised by those booking long-term. NGG also argue that there is potential undue discrimination against new NTS entry points which have no access to discounted NTS entry capacity. Another point made by NGG is that removal of discounts via GCM19 and application of LRMC based prices should ensure that locational prices avoid undue preference. NGG is of the view that zero reserve prices at all NTS entry points in the short-run allows users at non-competitive entry points to buy NTS entry capacity cheaply and costs are potentially passed on to other system users; and
- Competition is promoted: NGG argues that reserve price discounts inhibit secondary trading at NTS entry points and that removal of discounts via GCM19 will encourage more secondary trading.

Decision summary

The Authority has considered the relevant objectives and concludes that implementation of the modification proposal will not better facilitate the achievement of the relevant objectives of the Charging Methodology[59].

Ofgem considers that GCM19 would not better facilitate the relevant objectives as it would move to using the LRMC signal as the basis for daily entry capacity reserve prices, and in our view this would be to the detriment of efficient allocation of short-run entry. Furthermore, we consider that the proposals would have limited impact on auction revenues and the TO commodity charge which is the main aim of the proposal. Given the significant uncertainty around the level of change that could be brought about by this proposal, we do not have confidence that implementing this

[58] As set out in Standard Special Condition A5(5) ' Obligations as regard charging methodology' of NGG's NTS licence.
[59] As set out in Standard Special Condition A5(5) of NGG's Gas Transportation Licence, see: http://epr.ofgem.gov.uk/document_fetch.php?documentid=8783

proposal would achieve the intended aims or bring about the behavioural changes that its supporters hoped for.

However, in rejecting the proposal, we do not discount a number of the issues which the proposal has revealed to be important. NGG has submitted the proposal to address perceived problems with the level and volatility of TO entry commodity charges. We have explained why we do not consider that the proposal would achieve what it sets out to do, and why we have a principled opposition to the use of LRMC pricing as the basis for short-run entry capacity auction reserve prices, but in evaluating the proposal we consider that NGG could have done more to consider what cost reflective commodity and entry capacity charges may be. The proposal states a concern that TO entry commodity charges may not be cost reflective, and that day ahead and within day entry capacity charges are not cost reflective, but does not consider at a conceptual level the allowed revenues that capacity and commodity should collect and on what basis scaling to collect total allowed revenues should take place. In developing future proposals if NGG consider that this is not the case, and that it is not cost reflective to recover a high proportion of costs from commodity charges, we would encourage them to consider where this balance ought to lie.

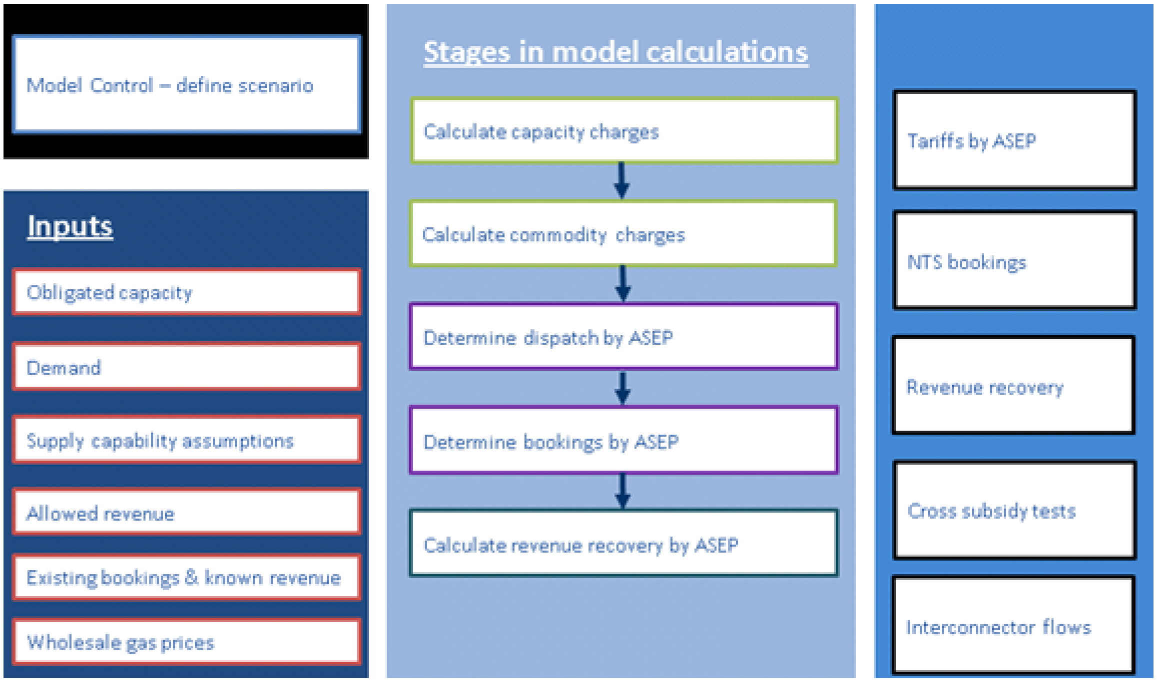
Appendix 5 – GTCR model

A5.1 The principal analytical tool we have used is a complex Excel-based model. We commissioned CEPA and TPA Solutions to develop a tariff and impact assessment model for potential changes to the structure of entry charges. As described above, the three key changes the model was designed to examine are: the level of short-term discounts, inflation indexation of long-term capacity charges and fully-floating entry charges.

A5.2 CEPA and TPA Solutions developed the model with input from industry, including through a series of four technical working groups hosted by Ofgem over the summer. A summary of the model is presented below. For a full description of the model, including assumptions, data sources, methodology and outputs see the CEPA/TPA report on our GTCR website. The model is available on request. You may find a copy useful to undertake your own analysis in informing your responses to this consultation.

A5.3 Put simply, the model starts with a series of input assumptions, runs the calculation stages for each year to 2028/29 and presents some key outputs. The outline model framework is shown overleaf in Figure A5 - 1, listing the key inputs, calculation stages and outputs. The inputs include demand based on National Grid's Future Energy Scenarios while the Allowed Revenue is based on the RIIO-T1 price control (uprated for years beyond 2020/21). The built-in outputs include, among other things, the derived annual entry tariffs by entry point for each year and the annual revenue recovery of NGGT across different categories of users.

Figure A5 - 1: GTCR model framework



Source: CEPA, TPA Solutions

The calculation steps contain a number of important assumptions that CEPA/TPA developed alongside Ofgem and with input from the technical working group. The

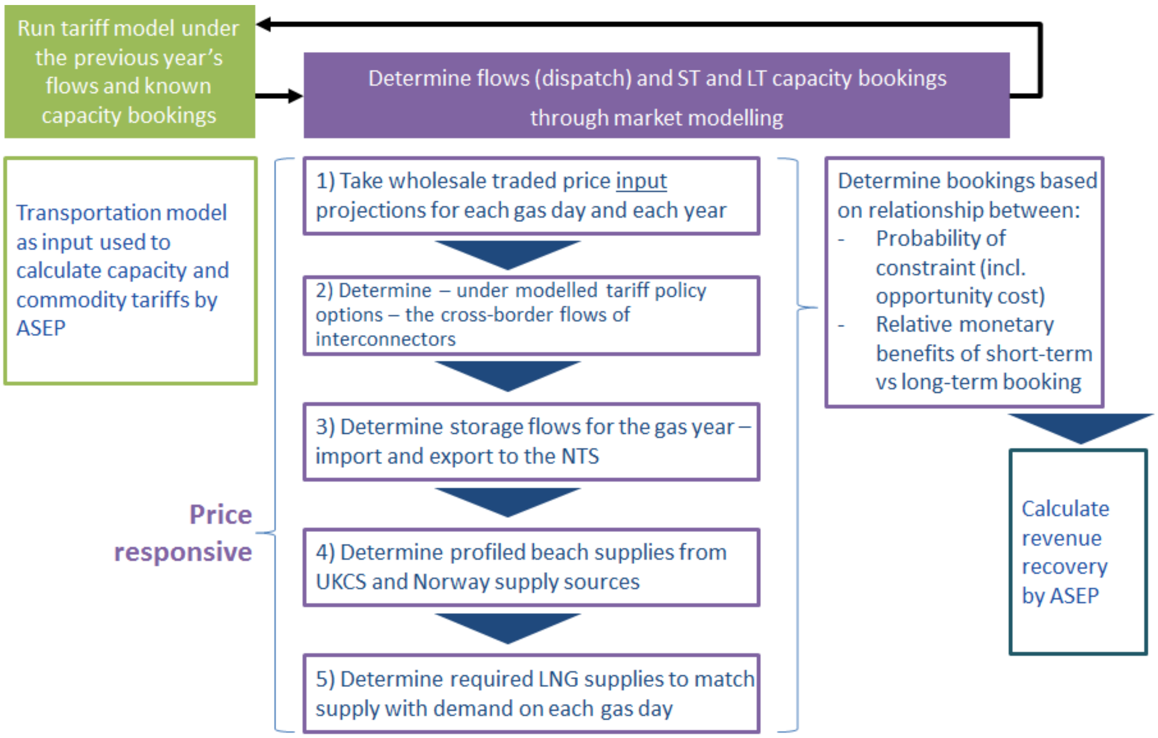
A5.4 Figure A5 - 2 overleaf summarises the calculation stages:

- The existing transportation model is used to calculate the LRMCs for each entry point, which, in combination with flows and capacity bookings, are used to derive charges.

- The model uses in-built market modelling to determine the flows of different supply sources to different entry points for each year. The flows are based on assumptions concerning price responsiveness of demand for NTS capacity for different supply sources. The model dispatch assumes that LNG is the swing source. The bookings are based on a combination of the relationship between the probability of constraint (including opportunity costs) and the relative costs of long- and short-term bookings. The total demand to be met is based on the National Grid’s Future Energy scenario (FES) selected.

- The outputs from each year are then used to calculate revenue recovery for each entry point, alongside other model outputs. The charges for the subsequent year are derived based on the previous year’s flows and known bookings, with the outputs for each year to 2028/29 dependent on the outputs of the previous year.

Figure A5 - 2: Steps in model calculation



Source: Ofgem, based on CEPA and TPA Solutions

Model data – price data

A5.5 As price data is a commercial product, we have published the model excluding price data so that users can input their own data. As an input to the model, price data has an impact on modelled outcomes, in particular with respect to cross-border flows between hubs.

A5.6 We have explored different sources of price data and discovered that, while the base case may be different between sources, the quantitative impact of the policy options is similar regardless of the pricing data used. That is, a policy option will have a similar impact relative to the base case, provided that common pricing data is used for the base case and modelled policy option. As explained above, given that we are exploring high level impacts, we do not consider that the price data used has a big impact on the modelling results. We have used ICIS Heren data from 2011/12 throughout our analysis.

Model limitations

A5.7 We discussed in Chapter 3 the simplifying assumptions made for the purposes of modelling. Table A5 - 1 overleaf provides a more detailed explanation of these limitations, including some of the early industry views on them (taken from the GTCR technical group's conclusions report, presented by the Gas Forum).

Table A5 - 1: Model limitations: summary and explanation

Shortcoming	Explanation	Gas Forum report views
NGGT's allowed revenue is known over the RIIO-T1 period (up to 2021). From 2021 onwards, NGGT's allowed revenue is set to remain constant in 2009/10 prices up to 2029[60], and the allocation of SO and TO allowed revenue is static[61].	We know NGGT's allowed revenue and the SO/TO split to the end of RIIO-T1. For the remainder of the period we have assumed an inflationary increase and no change to the split so that these variables do not distort the impact analysis when comparing charging policy options. Users may run the model with alternative assumptions.	
LNG is assumed to be the 'swing source' in the model's dispatch calculations, which influences the revenue recovered at different entry points, depending on supply source. An alternative dispatch schedule would result in different flows at different points over any given year.	To make the model manageable it assumes a common dispatch schedule for all model runs. This influences the flows and associated revenue recovery for different sources. The impact on these variables can be examined under the different policy options.	Not unreasonable given recent LNG flow patterns, although of course the future structure of the global gas market is highly uncertain. Projected increases in global liquefaction capacity may, for example, shift the position of LNG within the GB supply stack.
All entry points and supply sources are assumed to have the same probability curve for the risk of constraint. This effectively assumes that all shippers have the same risk appetite regardless of supply source or entry point.	This simplification was included to ensure the model was manageable. Users can change the assumed risk appetite to examine the results with different assumptions. We do not consider that this assumption undermines the impacts that we are exploring.	This is a very simplistic approach, however, it is recognised that it is impossible to model each individual shipper's risk assessment (and appetite for risk) and resulting booking strategy. It is accepted that the use of net flow compared to net capacity is appropriate
The potential for actual physical constraints within the network (at entry and	This reflects the current situation. Any modelled physical constraints would	

[60] This is equivalent to around 2.5%-3% year-on-year increase.
[61] This refers to the percentage split of the allowed revenue that SO gets vs the TO, according to RIIO-T1

exit) is not considered by the model.	be necessarily speculative.	
The model represents a static picture of the physical transmission system. That is, it does not explore new or additional sources of supply or changes to the characteristics of entry points, including any potential new entry points over the modelled period.	To incorporate changes to the characteristics of the system would require a more complex model and a series of further assumptions. We do not consider that such changes would materially affect the impacts we are examining.	Unrealistic assumption given the period under review, however, it is understood that forecasts of future supplies is fairly subjective.
Due to the uncertainty of TAR NC at the time of modelling, our approach to the dual regime may not be accurate.	Whilst we think that the aggregate system results are robust, we have less confidence over the precise levels of charges at Bacton CAM/Bacton non-CAM points62 under the dual regime arrangements.	

[62] These terms are explained in Chapter 1, page 11 (footnote)

Appendix 6 – Additional modelling results

A6.1 Table A6 - 1 sets out the policy options we have modelled.

Table A6 - 1: options modelled

		Base case	Dual regime	Fully-floating
Short-term discount* (see notes 1 and 2)	Current: 100% discount for within-day/interruptible 33.3% discount for day-ahead	a,b	a,b	n/a
	90% for all short-term	a,b	a,b	n/a
	30% for all short-term	a,b	a,b	n/a
	0% for all short-term	a,b	a,b	n/a
Premium*	120% for all short-term	a,b	a,b	n/a
Inflation indexation	a	No changes		
	b	Prospective inflation: applies to existing and new bookings, from policy introduction (2018)		

*the change to short-term discounts applies to within-day / day-ahead / interruptible capacity products only; monthly capacity pricing remains the same

Note 1: 90% discount means that a user pays 10% of the QSEC reserve price.

Note 2: This document concerns GB policy, and is consistent with the UNC terminology. Under TAR NC terminology, a 90% discount would be described as a '0.1 multiplier'

A6.2 As discussed in Chapter 3, we focused our presentation on the four key options:

i. Base case, current discounts;

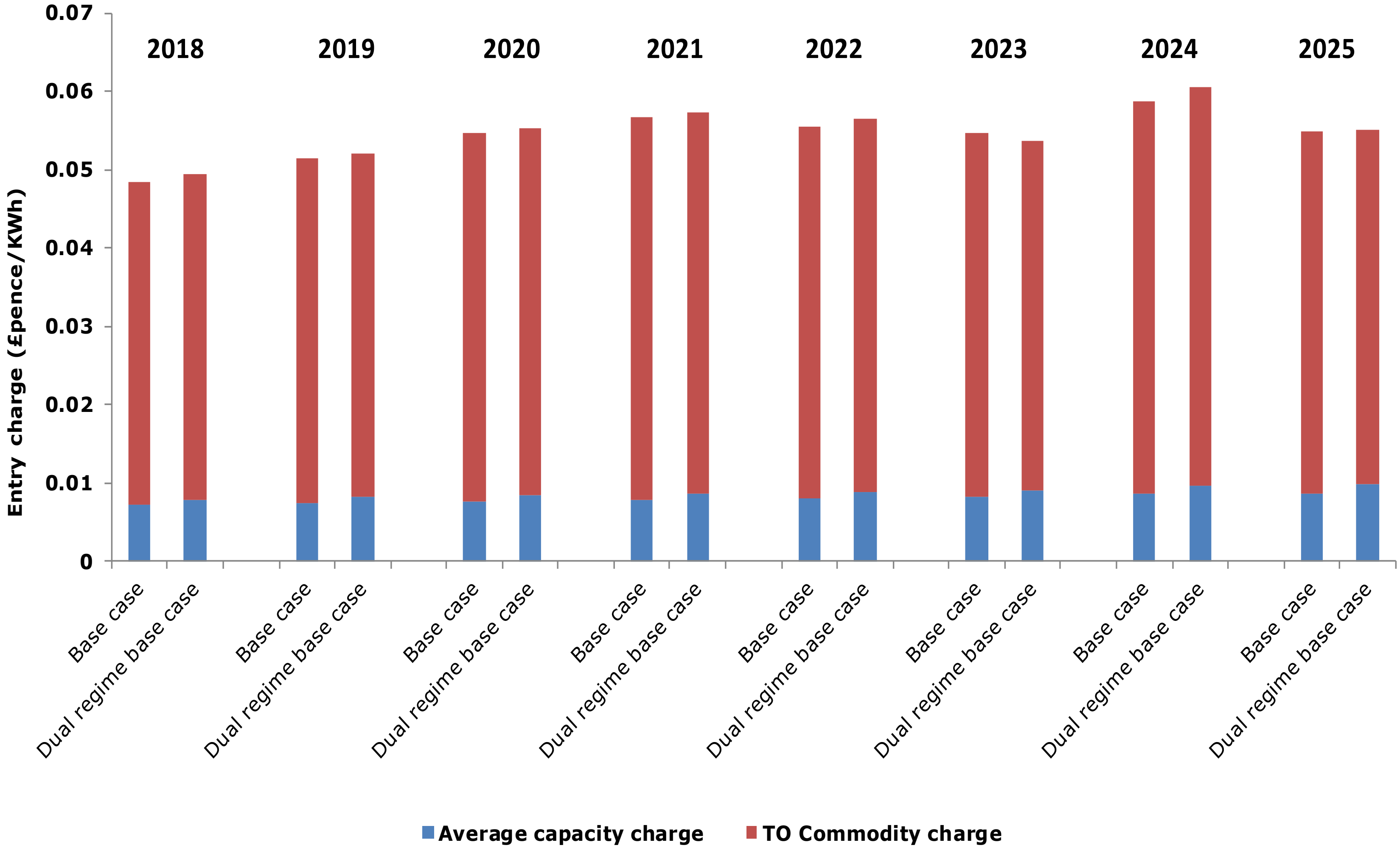
ii. Base case, 90% discounts;

iii. Fully-floating, current discounts;

iv. Fully-floating with 90% discounts.

A6.3 This section sets out the modelling results for the options not covered in the main text of the document, for completeness and transparency.

Figure A6 - 1: Comparison of average TO entry capacity charge and commodity charge for Base Case 1(current regime) and Base Case 2 (dual regime)



Note: bookings=flows for the purposes of calculating the commodity charge

Table A6 - 2: Entry charges at key entry points over time, under Base Case 1(current regime) and Base Case 2 (dual regime)

	Capacity charges (pence/kWh/day) and commodity charges (pence/kWh) at key entry points												
Option	**Entry point**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Base Case 1	Commodity rate	0.041	0.044	0.047	0.049	0.048	0.047	0.050	0.046	0.051	0.054	0.059	0.058
	Bacton - CAM	0.009	0.009	0.009	0.010	0.010	0.010	0.011	0.011	0.011	0.012	0.012	0.012
	Bacton - UKCS	0.009	0.009	0.009	0.010	0.010	0.010	0.011	0.011	0.011	0.012	0.012	0.012
	Easington & Rough	0.013	0.013	0.013	0.013	0.013	0.014	0.014	0.015	0.015	0.015	0.016	0.016
	Isle of Grain	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Milford Haven	0.020	0.022	0.022	0.021	0.022	0.023	0.024	0.025	0.026	0.027	0.028	0.028
	St Fergus	0.043	0.044	0.046	0.046	0.047	0.049	0.050	0.052	0.053	0.055	0.057	0.058
Base Case 2	Commodity rate	0.042	0.044	0.047	0.049	0.048	0.045	0.051	0.045	0.051	0.055	0.059	0.055
	Bacton - CAM	0.026*	0.027*	0.028*	0.029*	0.031*	0.030*	0.039*	0.037*	0.041*	0.046*	0.053*	0.051*
	Bacton - UKCS	0.009	0.009	0.009	0.010	0.010	0.010	0.011	0.011	0.011	0.012	0.012	0.012
	Easington & Rough	0.013	0.013	0.013	0.013	0.013	0.014	0.014	0.015	0.015	0.015	0.016	0.016
	Isle of Grain	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Milford Haven	0.020	0.022	0.022	0.021	0.022	0.023	0.024	0.025	0.026	0.027	0.028	0.028
	St Fergus	0.043	0.044	0.046	0.046	0.047	0.049	0.050	0.052	0.053	0.055	0.057	0.058

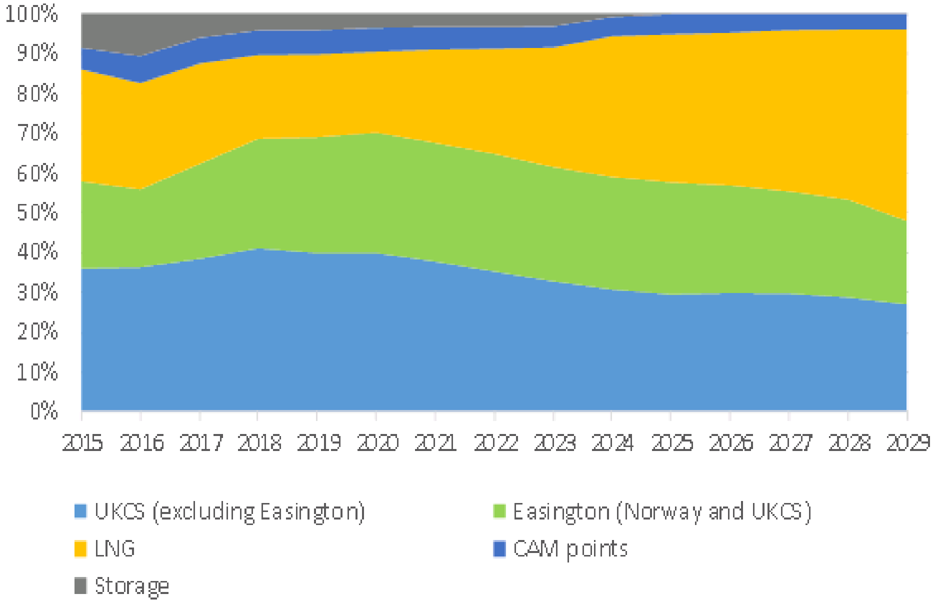
Under Base Case 2 - the dual regime – users at Bacton – CAM pay a fully-floating entry capacity charge, which is paid on bookings. All the other points maintain the existing capacity/commodity charge regime.

In most years, there is less than 1% difference in the commodity charge between the two Base Cases.

As discussed in Chapter 3, and illustrated in Figure 9 and Figure 10, actual charges payable by network users will depend on their individual bookings and flows decisions.

Figure A6 - 2: Revenue recovery by user group over time, under Base Case 1(current regime) and Base Case 2 (dual regime)

Base Case 1 (current regime)



Base Case 2 (dual regime)

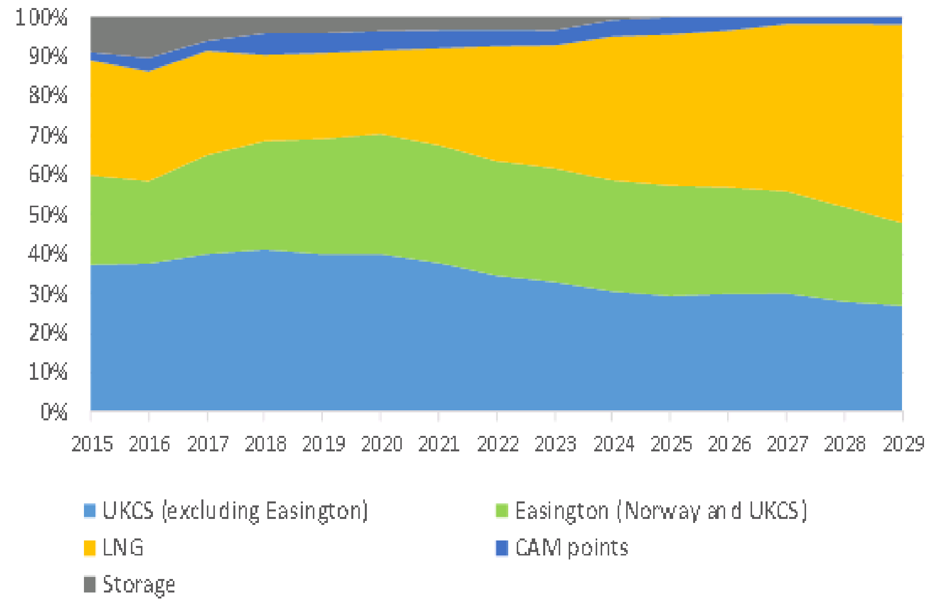
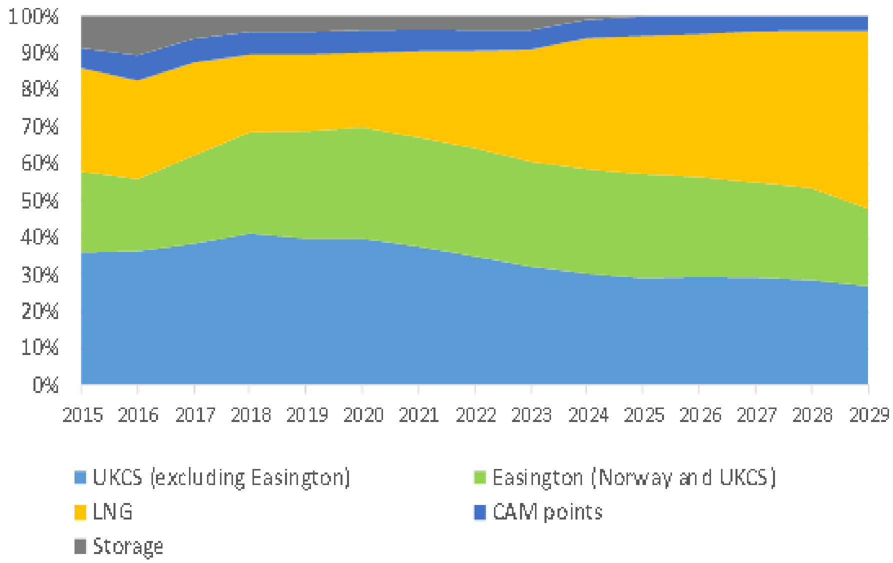


Figure A6 - 3: Revenue recovery by user group under Base Case (current regime) with and without inflation uprating of existing QSEC holdings

Base case (no inflation)



Base case (inflation)

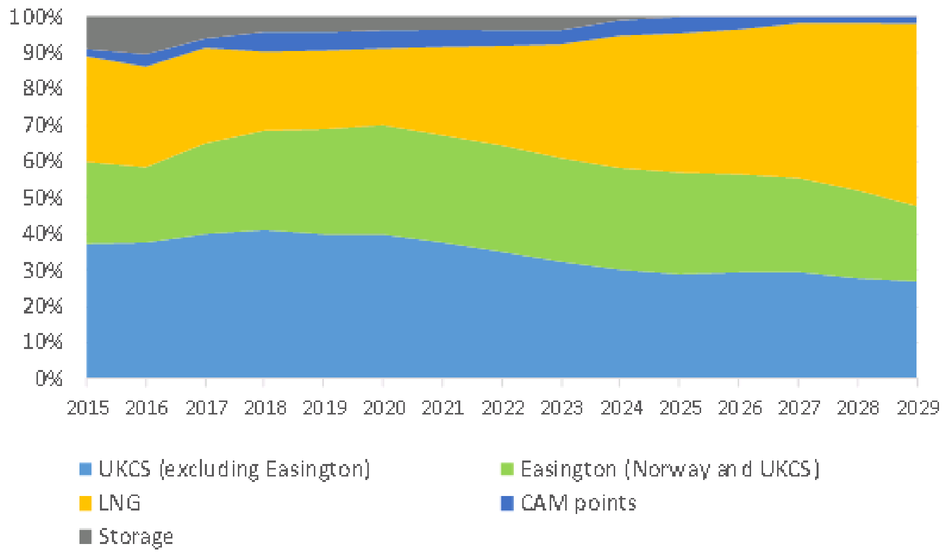
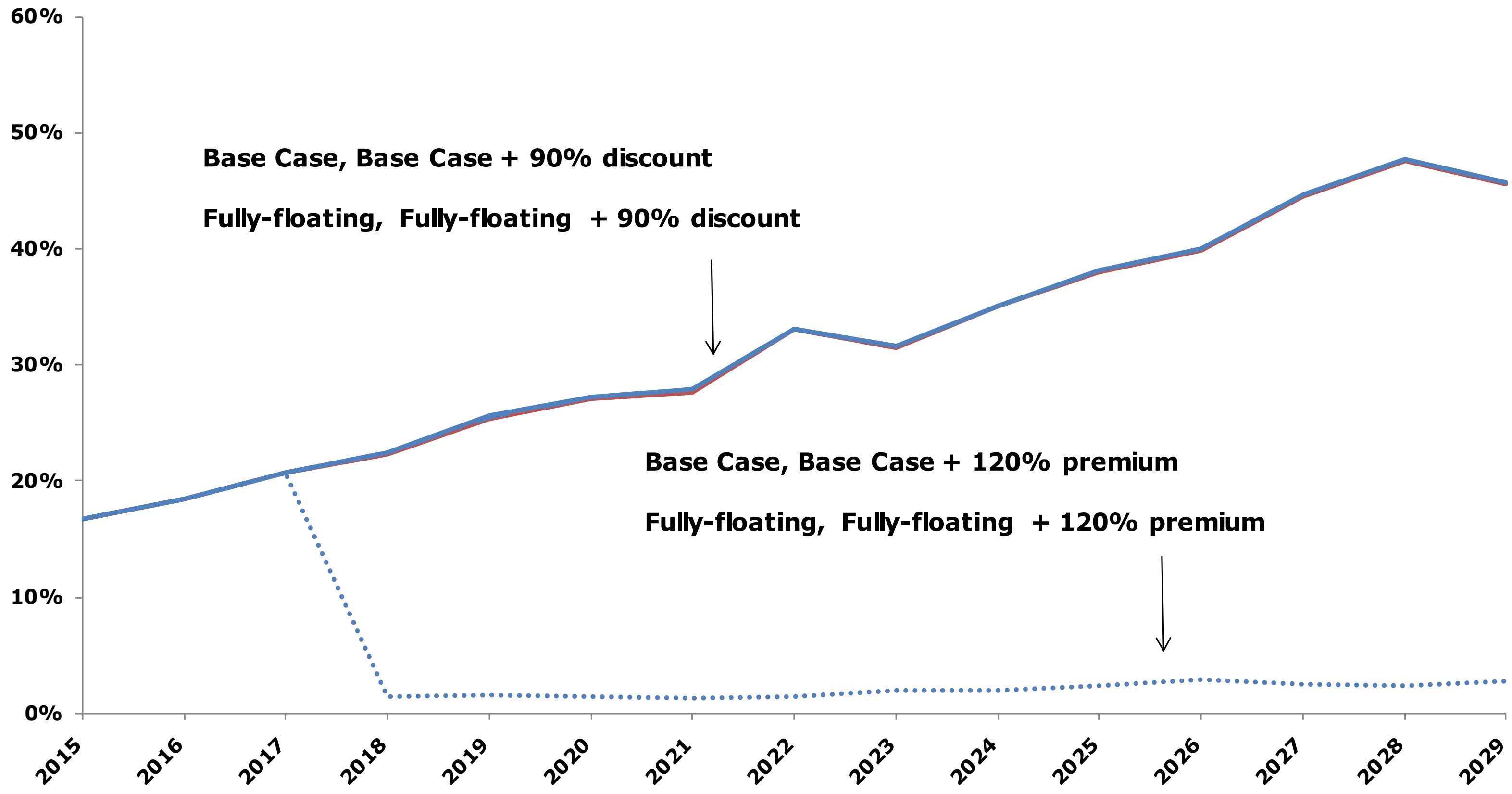


Figure A6 - 4: Short-term bookings as % of total bookings



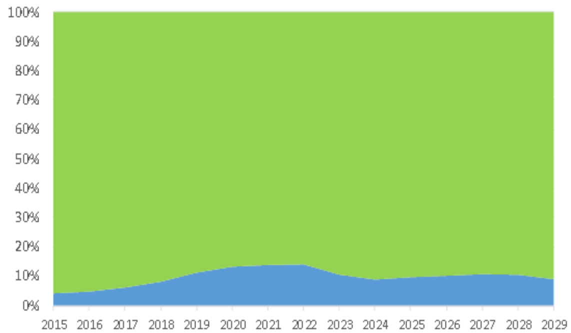
As long as short-term capacity is priced at, or below QSEC, the proportion of short-term bookings stays the same under all options (solid blue line). When short-term capacity is price at a premium to QSEC, short-term bookings fall dramatically.

Figure A6 - 5: Revenue recovery from short-term capacity over 2015-2029

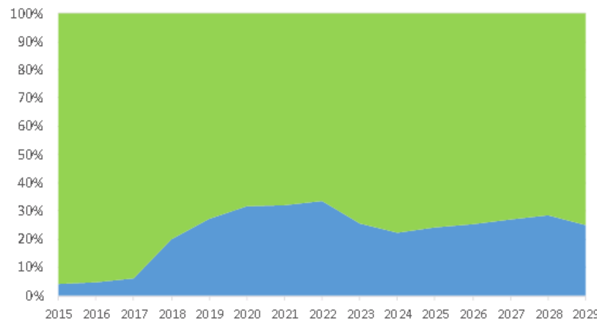
Blue area represents short-term capacity revenue

Green area represents QSEC capacity revenue

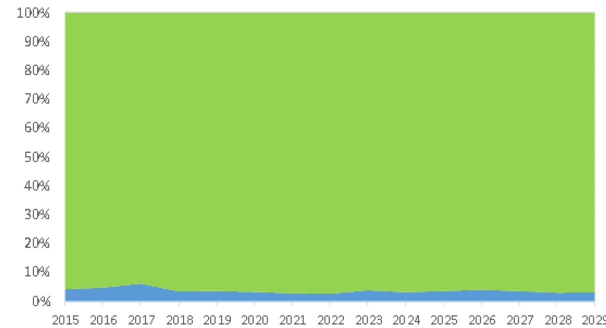
Base case



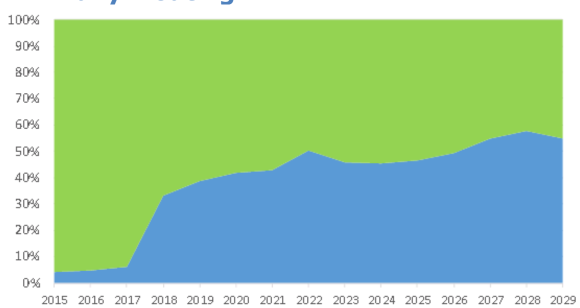
Base case +90% discount



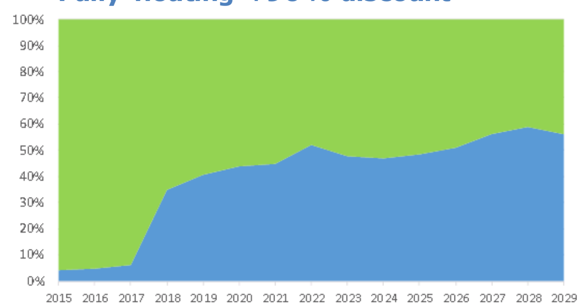
Base case +120% premium



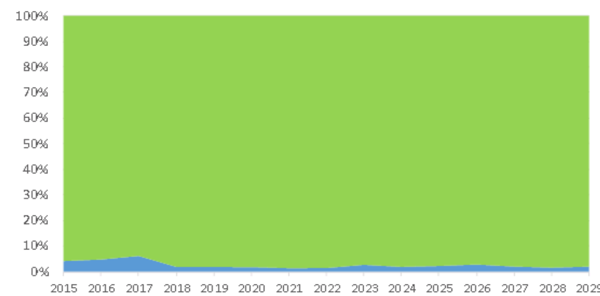
Fully-floating



Fully-floating +90% discount



Fully-floating +120% premium



Appendix 7 – Feedback questionnaire

A7.1 Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

A7.2 Please send your comments to:

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