For NTSCMF meeting - 11 February 2020
Industry Questions for CEPA

Questions have been received from 6 Workgroup Participants:

- Alex Nield, Storengy UK
- Julie Cox, Energy UK on behalf of members
- John Costa, EDF Energy
- Kirsty Ingham, ESB
- Nick Wye, Waters Wye
- Paul Youngman, Drax

The questions have been grouped into six sections

A. CEPA METHODOLOGY/APPROACH

Julie Cox, Energy UK

1. Are SO commodity charges considered? currently optional charge routes do not pay SO commodity charges?

We didn't include consideration of the SO Commodity tariff. We focussed on tariffs used to recover Transmission Services Revenue (as defined in the TAR NC). The SO tariff structure was not included within proposals for change under the modification proposals (other than in name).

The inclusion of the SO Commodity tariff would impact on the modelling in two ways.

1. It would impact on take-up of the NOC product and hence on revenue recovery (though some of the revenue recovery implications would relate to the SO rather than TO services revenue).
2. It would increase the likelihood of bypass investment (all else equal), assuming that bypass would allow avoidance of the SO Commodity Charge.

In respect of revenue recovery implications of take-up, for the NOC product to be attractive, revenue recovery contributions (across SO and TO services revenue) would have to reduce relative to the counterfactual. This would imply an increase in revenue recovery requirements from other users.

In respect of the increased likelihood of bypass, we set out in our analytical report the number of simplifications to the modelling of bypass that would be required. For example, we did not incorporate several costs of bypass (e.g. land costs) into our analysis. Even after accommodating the (assumed) ability to avoid the SO Commodity Charge, we continue to consider that the estimate of the likelihood of bypass included is an over-estimate.

2. How is the SQ (Status Quo) made to fit the bookings = flows assumption to enable a valid comparison with other modelled options. The reality of SQ is bookings > flows. When bookings = flows it makes no difference whether charges are capacity or commodity based.

We modelled the status quo using a consistent methodology with the modification options. To maintain consistency with the modification options, we also apply the assumption that bookings = flows (with the exception of GDNs) under the status quo. Given projections of spare capacity on the system in future years and the strong incentive to book capacity closer to real time, we would expect this assumption to be the most appropriate approximation of actual behaviour.

However, it is likely that some level of over-booking would remain given imperfect foresight and potential commercial drivers for use of longer-term capacity products. Hence, the assumption – as with all assumptions - is a simplification and means that the modelling of the status quo is unlikely to perfectly reflect reality. This is also the case for the modification options. Maintaining the same assumptions for both the SQ and modification options ensures consistent comparison between them. We did consider other assumptions and concluded that this approach was the most robust.

Unlike other models (e.g. climate, weather), the status quo modelling was developed to provide a counterfactual to the charging options which incorporated consistent assumptions and inputs. In addition, we used two scenarios, each of which produced a different set of outputs for both modelled options and the SQ. It is important that the counterfactual is modelled using a set of consistent assumptions to the modelled options rather than being designed differently to the modelled options. Applying the bookings = flows assumption is a good example of this – i.e. it is a necessary abstraction applied to both the modelled options and SQ.

We have noted the key assumptions and their implications for the SQ and the modelled options in Section 2 of the CEPA report.

3. How are existing contracts made to fit the bookings = flows assumption since not all existing bookings will be fully utilised by flows on all days e.g. storage, Caythorpe which does not physically exist or even on average across a year.

See p.12, Table 2.3: "Assumption: Existing Contracts". We assume that existing contracts are utilised first where there are corresponding flows at a point which has existing contracts in place. So, where our modelling suggests that there no flows at a point with existing contracts in place, those existing contracts are not used for actual flows.

Consistent with the methodology used by National Grid, these existing contracts still contribute towards revenue recovery even where they are not associated with actual flows.

4. For each model run is a simple check carried out that capacity booked x price in aggregate equals allowed revenue. Can this be provided?

National Grid's tariff model solves for total booked capacity to meet allowed revenue so this check is internalised in the model. In each iteration, when we produce flows for the tariff model, the tariff model solves to ensure that the tariffs associated with these flows produce the required revenue. National Grid's tariff model already included a check within the model that revenue requirements were met.

5. The term weighted average tariffs is used a lot what is the weighting by? capacity booked ? how do existing contracts feed into this ? Are flows assumed to flow against existing contracts first?

See p.23, section 3.2.1. For the avoidance of doubt, the same interpretation applies throughout. I.e. tariffs are weighted by capacity bookings.

The figures only include the 'standard' capacity tariff. I.e. they do not reflect existing contracts.

See response to question A.3 for clarification of the approach regarding flows against existing contracts.

6. Overall there is an expectation that allowed revenue / bookings (which equal flows) would be the same in all years for all options at the highest level, whether charges are capacity or commodity related. Is there a simple explanation as to why the weighting changes this, intuitively if some are paying less, others will need to pay more to ensure allowed revenue is recovered?

    a) At entry there are existing contracts and new bookings. Currently existing contracts pay fixed capacity charges and TO commodity charge. Other bookings pay capacity charges and commodity charges. Under 0678A all the commodity paid by existing contracts will need to be recovered from 'other' bookings, so overall 'other' bookings will pay more than now in aggregate, whilst existing contracts will pay less.

To ensure consistency of comparison, section 3.2 sets out the impact on annual capacity tariffs. Under the status quo, short term capacity products are booked at significant discounts. When these significant discounts are removed under the modification options, greater levels of revenue are recovered from short term products – in the case of the annual capacity tariff, this outweighs the impact of reduced revenue recovery from existing contracts. Hence the annual capacity tariff reduces under the modification options relative to the status quo. Annual capacity tariffs for standard products are also affected by total bookings/flows and any additional revenue recovery which needs to be realised as a result of take up of shorthaul products, storage discounts, revenue recovery exclusions, etc.

7. Please explain footnote 28 on page 24 of CEPA document. Why are CEPA scenarios used for peak supply and demand rather than those in the FES scenarios.

The transport model only included tariffs and LRMC 1-in-20 peak supply and demand assumptions for 2019/20. The status quo modelling requires determination of LRMCs based on modelling of 1-in-20 peak demand and supply scenarios for each year that is modelled. Therefore, we needed to develop scenarios of 1-in-20 peak demand and supply. Consistent with our modelling of the modification options we utilised the FES scenarios to develop these 1-in-20 peak demand and supply assumptions. This allowed us to develop SQ tariffs for future years. Using the FES, we then followed the methodology contained in the UNC TPD Section Y to produce the LRMCs.

8. How are SQ tariffs calculated for future years, beyond which NG have published values

Answered in response to question 7 above.

9. 5.9 in Ofgem doc p 67 refers to convergence. Is convergence always achieved? if not is there a revenue residual? how is this reported? What behavioural impacts are assumed?

See page 7, footnote 6.

All runs converged apart from the "Status Quo" and the "CWD with Storage" option. The level of change in tariffs was <5% for the "Status Quo" and <2% for the "CWD with Storage" option

Where convergence is not achieved there is no revenue residual as the final set of tariffs are calculated based on the solver in the tariff model which ensures revenue recovery.

10. We note that there are separate nodes for power stations using OCC but other generation is fed into the electricity model in aggregate or even called from the electricity model what are the effects of this? How does this aggregation inform the conclusions on marginal plant, assertions on closure, statements on tariff dispersion etc.

    a) Is this sufficiently granular to understand the impacts on individual plant? Table 2.4 of CEPA doc seems to suggest current users of off-peak capacity are not modelled in detail. This is a significant feature of the SQ that should be considered

See p.15, Assumption 'Gas-fired power stations'. Individually-modelled CCGT power stations in the model represent approximately 80% of the NTS-connected gas-fired generation capacity and a similar proportion of the gas flows – e.g. under the Two Degrees scenario, in 2030/31, they range from 86-88%, depending on the modelled charging option (including the status quo).

Note that the intention of modelling the electricity market is not to model the impacts on individual power stations (not in scope of analysis) but to consider the impacts on the electricity market in the aggregate – i.e. the impact on position in the merit order of (aggregated) gas plants vs non-gas plants. Necessary assumptions were made in the modelling of power stations in order to ensure model tractability. OCC power stations were disaggregated and modelled individually to consider the effects of the shorthaul product but other power stations remain aggregated.

11. Does the analysis referencing electricity charging take any consideration of the minded to or developing changes under the SCR?

See p. 14, footnote 12

12. The assumption of perfect foresight of bookings and therefore "book as flow" to commoditise the capacity charges for all but GDNs will likely show an underestimate of impacts on power generators who are running lower load factor, especially in a future environment of less predictable generation patterns and more provision of flex services from gas gen – does CEPA have views on this and an 'overbooking' sensitivity? An 'overbooking sensitivity' was suggested during a telecon between Ofgem, CEPA and Energy in September 2019. It was agreed this would be looked at.

The assumption of bookings = flows may have different implications for different types of market participant who may have different commercial bookings considerations. Nevertheless, for consistency, a single assumption of bookings = flows has been applied to all participants with the exception of GDNs.

We discussed with Ofgem the possibility of applying an overbooking assumption across all points (e.g. 10%) but agreed that this would not add much value as the commoditised weighted tariffs would simply increase proportionately for all points and the relative comparison between points would remain the same.

Alternatively, different overbooking assumptions could be applied at different types of points. However, we do not consider there to be an appropriate evidence base for the choice of the level of overbooking that is applied to each type of point in a robust way. In addition, the purpose of the modelling is to inform Ofgem's minded-to decision regarding impacts on consumers based on effects in the aggregate which is achieved without the inclusion of an 'overbooking' sensitivity. Therefore, applying a consistent 'bookings = flows' assumption across all users is considered most appropriate, robust, and proportionate.

13. CEPA doc P. 54 on closure decisions refers to the gas tariff increment as a proportion of the total cost, and that as the less efficient plant have higher costs anyway, the proportion of increase will be less material and therefore a good thing. But in terms of the merit order and bidding in a price to the electricity market, the absolute is what counts surely?

The discussion in this section is with reference to closure decisions only. We do not say that an increase in the tariff will be a 'good thing' but only that, in the context of the fuel, carbon and operations and maintenance costs only of a plant, the increase in the tariff will be unlikely to impact on closure decisions to a significant degree. This is even more so the case with less efficient plant given that the tariff increase represents a smaller percentage of total costs.

14. 5.37 page 76 commentary suggests some storage facilities do not inject gas into store over the course of the modelled year. Does this result in 0 for FCC? And hence no revenue from those facilities?

Yes. Where this is the case, this results in 0 for FCC at exit and hence no revenue from the exit tariff at such facilities.

Does the model link exit and entry flows so that in such years there are no entry flows either?

The model allows for storage facilities to optimise entry and exit flows over a two-year period (modelled for several months either side of the relevant spot year). Therefore, entry and exit flows for gas storage facilities do not necessarily match within a single year.

Footnote 34 on page 29 of CEPA doc seems to suggest that only seasonal flows are modelled at storage facilities?

Subject to injection and withdrawal constraints, gas storage facilities in the model can respond to price signals however they wish (i.e. not only seasonal flows). However, the deterministic nature of the model means that price shocks and short-run volatility are not fully represented in the modelling. This may limit short cycle gas injection and withdrawal relative to that observed in reality.

15. Why is most of the NOC analysis p78-82 of Ofgem doc based on 2030-31?

See paragraph 5.16.

In a number of areas, analysis in the main text is focussed on impacts under the TD scenario in 2030-31. Results for additional years and scenarios are presented in Appendix A of CEPA's report.

16. 5.54 on page 84 does the marginal supply source change under the modelled options? For the SQ how is it assumed that the currently diverse entry costs are reflected in the NBP price, it is probably an over simplification to say that it is rolled into the NBP price. Also see 3.2.1 in CEPA doc.

    Much of the analysis depends on a lower NBP price so understanding this is rather important, although it does acknowledge the difference is very small.

Yes, the marginal supply source can change for some periods of the year under each modelled option. Given that tariffs represent a small cost for market participants relative to price fundamentals, the impacts on the marginal source of supply are not always significant.

We make the assumption that entry costs flow into the NBP price where those entry costs impact on the marginal unit of gas.

17. 2.1.2 in CEPA doc is there any consideration of associated gas production in the supply elasticities?

Yes, supply curves consider both associated and non-associated gas using several years of historic daily production data from all main offshore terminals.

18. CEPA doc page 27, CWD and PS comparison thought CWD exit charges in Scotland were relatively high?

For CWD, exit charges are based on the flows observed at entry points across the system. Based on our modelling of the TD scenario and in 2030-31, we find exit charges to be higher under the PS than CWD in Scotland.

B. CAPACITY METHODOLOGY

Nick Wye, Waters Wye

1. Where you state entry and exit tariffs as weighted averages, are these the weighted average prices for capacity, not including Existing Contracts i.e. only represents the weighted average for all "new" capacity?

Yes

John Costa, EDF Energy

2. The analysis showed Gas prices coming down from lower annual average prices due to large protection for Existing contracts (even larger discounts than today as they don't pick up Rev. Recovery charges) meaning those new purchasers of Entry Cap will pick up majority of Entry costs.

   Are there any ratios in the analysis to show the revenue effects of this? E.g. [10%] of Entry shippers will pick up [70%] of costs…declining out to 2030? It would be good to see a chart similar to Ofgem's Figure 0.2 in their decision letter tracking the ration in revenue collection between existing and new entry cap holders.

Ofgem considers the information contained in its report (e.g. in Figure 0.2) sufficient to reach a minded to decision.

Paul Youngman, Drax

3. Figure 3.3 sets out the average tariff, weighted by the volume of capacity bookings, at each entry point. The figure also illustrates the dispersion of tariffs at entry points under each option.

   It is not clear how this analysis has been completed and if it would reflect the outcome of a benefit in reducing the wholesale price of gas

   a. The charge has been 'commoditised' and is not based on booked firm capacity or the FCC but based on flows. is this the case? If it is the case then do you agree that the model is not reflective of the capacity booking or FCC applied when constructing the tariffs?

      "*Given our assumption that bookings are equal to flows for all points other than GDNs, the capacity tariff represents a charge on each unit of gas flowed – i.e. it is effectively 'commoditised'. In effect, the charts compare the tariff paid to flow one kWh of gas making use of the annual capacity product both under the status quo and under the modification options.*"

See p.12 Table 2.3, "Bookings and Flows"

   b. Given that the same absolute value would be collected at entry under the Current or any proposed methodology can you explain how there is a disparity in the average tariff ? Is this due to any assumptions or model differences that appear in some models but not in others ? Could it be due to the scenario referred to in footnote 28 ? Can you provide details of how this scenario differs to that used to assess the different proposals?

Note that the commoditised annual capacity tariff is presented. The annual tariff (for each point and in sum) is impacted by the amount of revenue which is recovered from non-annual products which increases relative to the significant discounts under the status quo. It is also impacted by additional revenue recovery requirements due to e.g. a NOC product, an 80% storage discount, etc.

See response to question A.7 in relation to the scenario for the SQ.

c. Was the SQ scenario completed with or without existing NOC in place ?

See Table 2.2. With existing OCC in place.

d. Exit - fig 3.4 effectively a similar question as to entry but here it is more pronounced as the average weighted capacity tariff is different across classes of exit customer - can you explain why this there is a difference, given that under Postage Stamp all exit capacity will be paying the same charge p/kwh/day ?

See response to part b. for a general explanation of why weighted average annual capacity tariffs change across classes.

See p.12, Table 2.3 “Booking and Flows” which explains why PS tariff is different for GDNs as opposed to other points. I.e., because the charge is commoditised, and because GDNs overbook, they will pay a higher capacity charge per unit of actual flow.

e. How do the values fig 3.10 relate to the Ave weighted tariff in fig 3.3 and 3.4 ? Given that the analysis may be flawed in not comparing the impact correctly what confidence level do you place on the wholesale price reduction benefit? to what level could there be a disbenefit ?

Figures in 3.10 represent the impacts on the wholesale gas price, which is affected by tariff changes on the marginal unit of gas on average.

The analysis suggests the impacts given in 3.10 on the wholesale gas price which results from the marginal sources of gas supply facing a reduction in their gas tariff in the aggregate.

Modelling is an abstraction from the real world requiring a number of assumptions with the most important assumptions set out in Section 2 of the CEPA report. Therefore, some level of uncertainty is present within this, and all, modelling. Within the structure of this model, incorporating assumptions and inputs that have been discussed, all impacts on the gas and electricity prices were found to be small but significant at the 95% confidence level when the price series was compared for each option against the status quo using a t-test.

f. P35 "This suggests that the reduction in the annual capacity tariff at entry points (see Figure 3.3) leads to a reduction in the costs of the marginal unit of gas on average and hence to a reduction in the wholesale gas price." - under all models the same absolute value is being collected so how can this statement be true? Is there some cross subsidy between Entry and Exit that leads to Entry paying less under particular models.

The effect is due to the impact on the *marginal* unit. Modification options may allow for marginal entry sources to pay less on average where inframarginal sources pay more on average. Where this is the case, this reduces the wholesale gas price.

C. OPTIONAL COMMODITY CHARGE (SHORT-HAUL)

Nick Wye, Waters Wye

1. Your shorthaul analysis does not include the discount relating to SO commodity charges in the SQ. Please confirm that this is correct?

Please see response to question A.1.

2. Can you provide more detail as to how you have incorporated the NOC discount into your calculations e.g. have you assumed that the discount is shared 50:50 between entry and exit points?

In calculating the tariffs, we have followed the approach set out in the relevant proposed modification:

- Under NOC 1 (Mod 0678B), entry and exit NOC tariffs are set with reference to the respective capacity weighted distances for the entry and exit point of a given shorthaul route (see p. 26 of the FMR).
- Under NOC 2 and Wheeling (multiple mods), the NOC tariff was set at the route level, and then a 50:50 split between entry and exit NOC tariffs.

In modelling the uptake of the shorthaul product, we compared the full entry-exit tariff of a given shorthaul route with the standard tariffs for the respective entry and exit points. Similarly, flows on a given shorthaul route were optimised on the basis of the full shorthaul discount.

3. Can you confirm that you have included the "annual fee" in your NOC calculations, where the fee is set out in NOC2 proposals?

We have included the annual fee where this is set out in the proposals. We spread this fee on a per unit basis.[1] This is possible as we iterate between our market and tariff models, meaning that the annual fee is considered as part of the shorthaul uptake decision and shorthaul flow optimisation.

Kirsty Ingham, ESB

Section 4.2 Bypass Investment (P56)

4. Does the bypass investment analysis at 4.2 incorporate adjusted assumptions to the NOC formulae in the Mod proposals (per the tables in Section 0)? If so, why do the tables in 4.2 refer to the Mod options (e.g. NOC 1, NOC 2)? Have the formula adjustments been made elsewhere in the report? If the bypass investment section uses the adjustments and the rest of the report the proposed formula in the Mods, how does this compare apples with apples?

The bypass analysis includes the tariffs as calculated by following the respective NOC methodologies. However, for estimating the costs of building a bypass pipeline we have used the structure of the formulas for costs contained in the relevant methodology but have applied

[1] I.e. on a p per kWh/d basis (which is equivalent to p/kWh given our bookings = flows assumption).

assumptions which are more consistent with a commercial investment rather than regulated infrastructure (e.g. cost of capital, assumed commercial lifetime, etc). See Table 2.7 in CEPA report for those assumptions.

5. Why does Section 0 mention 25 year lifetime for a pipeline but 4.2 shows results only for 5 years? Why assume build to MNEPOR but flow to load factor in the modelling? If the info is available, why not build to perfect foresight of capacity need (similar to the capacity booking assumption)?

See p.21, Table 2.7, "Infrastructure Asset Life" and 'Size of bypass pipeline" for explanations of assumptions.

The 25 year lifetime is the assumption for the commercial life of the pipeline. However, the five year horizon is a 'payback period' assumption. I.e. it is used as the basis for whether the decision would be made to bypass or not.

John Costa, EDF Energy

6. What is the impact on electricity prices from the £533m extra transportation costs CCGTs pick up in the analysis? CEPA state these costs are likely to be recovered from the Cap. Market (but do not model this) or electricity wholesale however "the effect likely to be limited". Why is this?

Additional costs to CCGTs are included in consideration of the impacts on the electricity market price. I.e., the electricity market price goes up where the combination of the gas tariff *and the gas market price* increases the costs of the marginal unit and goes down where the combination decreases the costs of the marginal unit. On average, while we identify an increase in transportation costs as you point out, we observe that the impact of the combination of the gas tariff and gas market price is to reduce the costs of the marginal unit of electricity and hence, electricity prices go down.

Note that it is possible for the combined costs of the gas tariff and the wholesale market price to CCGTs collectively to increase while the costs of the marginal unit may fall on average.

The implication is that, on average, for the marginal unit, any increase in gas input costs resulting from higher gas tariff is countervailed by the reduction in the gas market price.

7. Given the stark figures in CEPA report below (NOC worth £1.10?Mwh and £533m of extra CCGT tariff costs) a large proportion would be expected to be from wholesale mkt for the reasons below. What is CEPA's view on this?
    a. The report states that CCGTs relying on Shorthaul is worth £1.10/Mwh so by the same token we would we expect to see power prices go up by this amount for the following reasons:
        i. 80% of CCGTs were using NOC,
        ii. Ofgem's view is that CCGTs will still profile day-ahead as today (given the increase in p/kwh capacity costs and the 10% discount benefit)
        iii. plus CEPA's view that CCGTs will become even more marginal going forward.

In addition to the response provided to question 6 above, note that approximately 80% of the NTS-connected gas-fired generation capacity and a similar proportion of the gas flows are modelled individually in the market model and so are able to use the NOC product. This does not mean that all of these CCGTs take-up the NOC product in the modification options or under the status quo. Take-up of the NOC product for those who have the option of using it is modelled endogenously. Take-up levels are set out in Table 3.1.

b. CEPA state that electricity prices would increase if there a NOC was reintroduced. Given that 80% use NOC currently this must mean the 20% not using NOC are marginal plant whose transportation costs would increase to make up the remaining Allowed Revenue recovery. Is this correct?

In addition to the impacts of the NOC discount and gas tariffs on CCGTs, the wholesale gas price (an input cost to gas generation) also needs to be included within considerations of the impacts on the marginal plant and the electricity price.

As noted above, 80% of NTS-connected gas-fired power generation capacity and

8. Does your analysis assume all CCGTs not utilising shorthaul are currently paying full TO and SO Exit Commodity charges?

See previous responses with respect to SO Commodity charges.

9. Is it possible to have the Revenue breakdown B.2.4 for the 3 time points CEPA calculate CCGT tariffs for (2022, 2026 and 2030)? This would highlight revenue distribution trends across this 10 year period – e.g. the SQ CCGT price discrepancy to PS is largest in 2030 (0.030188p/Kwh compared to 0.023490p/kwh) implying increasing trend / greatest consumer welfare in 2030. Why is this, due to lower running hours from CCGTs or other?

Ofgem considers the information contained in its report (e.g. in Figure 0.2) sufficient to reach a minded to decision.

Julie Cox, Energy UK

10. 5.47 Comments on NOC 2 methodology suggest a maximum route distance of 25km and average of 10.2 km but this is considered to include routes which are not credible, is it correct to assume any new approach needs to reduce these numbers?

CEPA cannot comment on this.

11. Can you explain how you came to the conclusion that Power Stations in aggregate would have lower charges under the Postage Stamp model?

We are not clear what 'conclusion' this refers to. For the avoidance of doubt, the analysis in section 3.2.2. does not incorporate impacts of shorthaul products (see p.23, footnote 24 in relation to 'standard annual capacity tariff').

Specifically:

a. What assumptions have you made about the utilisation of shorthaul for the approx. 50 CCGTs in the UK? (i.e. specifically how many are currently benefitting from shorthaul?)

Utilisation of shorthaul is endogenous within the model. Network users that are eligible will use the shorthaul product where there is a commercial benefit to doing so. Table 3.1 in the CEPA report sets out the number of routes that use the shorthaul product under each option.

b. Does your analysis assume all CCGTs not utilising shorthaul are currently paying full TO and SO Exit Commodity charges?

See previous response wrt. SO Exit Commodity charges

c. What is your assumption of the split between firm and off-peak bookings?

We have used historical proportions (2017-18) of bookings of different types of capacity product in order to inform assumed splits of different capacity products going forwards.

d. Page 26 of CEPA doc seems to suggest that SQ and mod comparison only considers annual tariffs so does not consider shorthaul, but also recognises that many power stations and industrial sites use the OCC which provides a discount to the annual tariffs so the comparison and charts are not very informative? This also seems to contradict CEPA's initial assumptions that seem to incorporate off-peak and OCC.

The inclusion of annual tariffs is for presentational purposes (in the case of the modification options (with multipliers of 1, the choice to represent the annual product tariff does not have significant implications). The model incorporates tariffs for all products (including any shorthaul product where it is taken up) and hence, the impact on the wholesale gas and electricity prices result from a combination of all tariffs.

Impacts on individual power stations are not within scope of the analysis. Instead, the aggregate effect on the gas and electricity markets have been the focus of this modelling.

We also note that the 'shadow tariffs' for the NOC products are presented in Table 3.2.

D. CONSUMER IMPACT

Kirsty Ingham, ESB

1. Section 3.5.2 Impacts on gas interconnectors - Moffat Revenues

    a. 3.5.2, p.48: CEPA states that its modelling suggests that the Irish gas price is lower than the GB gas price by the amount of the shorthaul discount. Does CEPA's model not take into account the GNI Entry price to access the IBP at Moffat?

In line with the scope of the analysis (i.e. focussed on GB), it does not include the GNI entry price

    b. What was CEPA's reasoning not to treat Moffat as demand with an attached elasticity rather than treating it similarly to the bi-directional merchant interconnectors?

This is consistent with our use of a global gas market model which endogenously calculates supply and demand equilibrium for each country.

    c. What consideration was given to Northern Ireland?

We note that our work under this project was limited to the scope of the quantitative analysis that we were commissioned to undertake and that this was in relation to impacts on GB consumers. The consideration of the issue highlighted in this question is a matter for Ofgem - who set out in its Minded-to decision where it had considered the NI effects.

Nick Wye, Waters Wye

2. Can you provide more info concerning the marginal source of supply used to determine gas prices? It would be helpful to provide some commentary on any changes to the source across the periods modelled

The marginal source of gas supply is endogenously determined by the model based on global commodity prices, operational costs, tariffs, etc.

Please see Figure 3.1 and Figure 3.2 which provides an example of the sources of gas supply under the TD relative to SP scenario in the 2030-31 spot year.

E. STORAGE

Alex Nield, Storengy UK

1. What assumptions and prices have been used in the modelling of price spreads for driving flow behaviour at storage sites?

Storage modelling is optimised endogenously so no price spreads were assumed to drive its behaviour. If storage is in the merit order (which is a function of its cost structure, cost structure of other competing flexibility solutions etc.) then it will be used; competition between storage and other flexibility sources are determined within the model; hence, seasonal price spreads themselves are endogenous.

2. On page 29 of the CEPA analytical support document (section 3.2.4), you say that there are "no exit flows at several storage facilities within the year modelled". Are you able to provide further details and clarification on this?

Storage injection and withdrawal was modelled over a two-year time horizon with the model allowing storage injection and withdrawal over a period either side of the spot year in question. As such, flows at storage facilities can be optimised over this two-year horizon. This means that injection and withdrawal do not need to match within the spot year in question.
It is also important to note that the model is deterministic – i.e. it does not reflect stochastic events (shocks) and price spikes. Non-seasonal injection and withdrawal patterns are possible in the model but are likely to be under-estimated as a result of this modelling approach.
Under these conditions (i.e. dampened price volatility), and with declining gas demand, there is often spare capacity in the system from other sources of entry which are able to compete with storage for short-term flexibility.
Therefore, particularly for short-range storage facilities, we can observe low levels of injection (sometimes zero) over the course of some spot years under some scenarios.
Because of the deterministic approach, we focus on the tariff impacts (not including wholesale market and operational cost impacts) when considering the potential impact on storage investment and closure decisions.

3. What provision has been made in the analysis for the benefit of within day flexibility provided by storage?

These elements are not within scope of the modelling.

4. What assumptions have been used on the levels of cycling each year for different storage facilities?

There is a limitation on the rate of injection and withdrawal which is specified for each storage facility. Overall storage volume capacity was also included in the model as a constraint. We didn't force the model to cycle storage and storage operations. Therefore, cycling was endogenously determined together with all other supply options to determine the optimal merit order for each day.

5. What assumptions have been made in assessing the increase in variable (eg injection and withdrawal) costs to storage?

We apply this as a marginal cost. Therefore, higher flows led to higher variable costs (these variable costs are presented in comparison to the status quo in Figure 3.27). We included injection and withdrawal variable costs as part of marginal cost.

6. Figure 3.27 on page 51 of the CEPA analytical support document, appears to show a large increase in storage revenues from wholesale gas prices combined with an increase in operational costs, that results in a profit for storage:
   a) Please can you further explain what is shown by this graph.

Please see paragraph above the chart.
Note that, as stated in 4.1.2, the complexity of gas storage commercial injection and withdrawal decisions and the deterministic nature of the modelling makes results less certain in this area. We therefore focus on gas tariff impacts only (i.e. not including impact of wholesale gas prices) when we discuss potential long-run impacts on gas storage facilities.

   b) Please can you provide further detail on the assumptions and data used for this analysis.

Responses to the questions above provide further detail on the modelling approach, data and assumptions used.

7. What scenarios have been modelled when considering the potential long term impacts on investment and closure?

Long term impacts have not been modelled in the same way as the impacts in spot years out to 2030/31.
Instead, tariff and revenue impacts resulting from modelling analysis presented in Section 3 of the report (e.g. under TD and SP) has been compared against wider commercial factors to illustrate the potential for long term investment and closure impacts.

8. What share of the customer billing is attributed to the management of price/market volatility, and for NTS system balancing?

These elements are not within scope of the modelling.

9. On page 29 of the CEPA analytical support document, you talk about short-range, medium-range, and long-range storage sites. Please can you clarify your definition of these terms and which sites are included under each category.

The reference is to footnote 34. Medium/long range storage sites refer to those that generally cycle on a seasonal basis and short-range refers to those that cycle more frequently (fast-cycle).
We modelled the following active storage points:

Storage facility	Long- or short-range?
Hatfield Moor	MR/LR STORAGE SITE
Hill Top Farm	SR STORAGE SITE
Hole House Farm	SR STORAGE SITE

Holford	SR STORAGE SITE
Hornsea	SR STORAGE SITE
Barton Stacey (Humbly Grove)	**MR/LR STORAGE SITE**
Stublach	SR STORAGE SITE
Garton (Aldbrough)	SR STORAGE SITE

National Grid's tariff model also included some further storage entry and exit points with 0 FCC.

F. ASSUMPTIONS OVERALL

Kirsty Ingham, ESB

1. Pages 12-13 and 15 state that recent product booking proportions are taken into account in the modelling (e.g. offpeak, shorthaul), yet the commentary around the charts through the text appears to show the status quo as the full charges prior to discounts. What exactly is meant by status quo? How has Offpeak been incorporated into status quo when comparing to the other options?

For presentational reasons, we present only the standard annual capacity tariffs in Section 3.2. However, we have incorporated the impact of all tariff products for both the status quo and modification options within the modelling in full.

The proportions of all products for all entry and exit point types have been assumed to remain at the levels observed in gas year 2017/18. This applies to the status quo as well as to the modification options.

Additional clarifications raised at NTSCMF

1. Can you clarify your approach regarding modelling of entry/exit tariffs at non-GB interconnector entry/exit points?

We can confirm that entry/exit tariffs at the non-GB interconnector entry/exit points are not included within the modelling.

2. Did you perform any backcasting of shorthaul take-up?

For reasons given in response to question A.2, we did not carry out any formal back-casting of the shorthaul element of the modelling.

We did compare our results of take-up of the shorthaul product against National Grid's to help provide a rough sense check. A summary of the comparison is provided below:

	Modelled/registered routs	Number of routes that use OCC product	Flow on OCC (TWh/year)
NGG summary of OCC use for Gas Year 2017/18[2]	54	37	244.5

[2] See: https://gasgov-mst-files.s3.eu-west-1.amazonaws.com/s3fs-public/ggf/book/2019-04/Optional%20Charge%20Analysis%20%28National%20Grid%29%20v1.3.pdf

CEPA modelling of SQ (TD, 2030/31)[3]	48	35	167.4[4]

[3] See Table 3.1 in our report

[4] Note that total gas flows on the NTS in 2030/31 TD scenario are lower than in 2017/18 which explains some of the difference in total flows.