nationalgridESO

Questions and Answers

Transmission Charging Forums (October 2019)

Please note that since the Transmission Charging Forum took place in October, Ofgem have published their decision on the Targeted Charging Review. As a result, the answers given during the forum to the below questions - in relation to how BSUoS is levied, the application of the residual element of TNUoS (for both Generation and Demand), and how Demand tariffs are calculated – will not reflect those decisions or the changes that will be required. For more information on the Targeted Charging Review, please see here.

BSUoS Forecasting, Reporting & Billing

What's the difference between trading costs and BM costs from Elexon?

They are essentially two different tools that the Electricity System Operator (ESO) uses to balance electricity supply and demand. To meet forecast ESO balancing requirements at minimum cost, ESO trades energy related products forward in time. These trades are done ahead of gate closure. BM costs are the costs for Bids and Offers in the one-hour period directly after gate closure known as the balancing mechanism.

Will the New BCR file change name?

We have no current plans to change it from its current name.

Over the past couple of months there have been higher constraint cost, what are the drivers for that?

More actions are needed when the weather is changeable. In the past year or so we've seen some big changes, e.g. Nemo came on, there are record levels of wind/solar on the system which require more careful management than conventional technologies, so we need to take more actions.

Is trading volume/cost attributed to the settlement period in which it was purchased or the Settlement Period it is settled out at (e.g. a forward trade for energy)?

We trade for specific delivery windows – the costs of these trades are applied within the BSUoS charge to the settlement period during which the trade is delivered.

Do NG publish historic breakdowns of BSUoS by element costs?

Not specifically, but customers receive a breakdown of BSUoS costs within their BCR file and from this year we also started publishing the BCR files on our website. The BSUoS monthly forecast also shows outturn costs split by category for the BSUoS charge, these have been published on our website since June 2018. Prior to this BSUoS information was included in the Monthly Balancing Services Summary (MBSS report). There are other sources of data available for BSUoS charges and we published a document to help direct people to these sources that is available here. Our data finder and explorer is another tool that can assist people in finding the information they are looking for which can be found here.

Is there a clear reason why NG's Long Term BSUoS forecasts have historically been so far below actuals?

The monthly forecast is quite close to the actuals. We do aggregate up to an annual forecast and the costs are generally driven by system outages and weather conditions which we are unaware of at that stage (e.g. if western link is available it makes a massive difference on windy days, if it trips off and is unavailable it creates costs we were unaware of)

Should the HVDC link publish its availability information in real time as it impacts the constraint costs (i.e. BSUoS costs) significantly?

The HVDC link is a TO asset which means we would not be able to publish the availability.

How do you expect the BSUoS reports to drive informed business decisions? Flexible generators need accurate forecasts at hourly granularity by early morning D-1.

BSUoS report is to inform the industry of a forecast of balancing the system spend which will factor in to costs. We publish a half-hourly BSUoS forecast daily for the industry to use.

Is it possible to get BSUoS forecast scenarios for major potential swing events? I.e. HVDC link being out.

We provide forecast based on our best view at the time and it is difficult to forecast scenarios as it depends on what is happening in the system at the real time. We will consider what analysis we can provide to support the industry.

Following the reduction of ESO incentive from BSUoS for 19/20, what will happen to the incentive in future years?

BSUoS charges – The new incentive scheme was introduced last year. We are still in process of learning with Ofgem. In future years we will aim for as accurate initial recovery as possible but there will always be an element of true-up due to the final decision coming after the end of the scheme year.

How are BSUoS costs kept under control?

The NGESO works hard to minimise the balancing the system cost and reduce the cost to the end consumers. Here is a report explaining in more detail how we perform this role.

Does the BSUoS daily balancing report charge estimate include the ESOs internal/incentive costs?

Yes, we do cover the incentive cost and internal cost in the daily report. Please note that we have suspended the incentive costs for this year 2019/20.

Is there a breakdown of the BM costs?

There is a breakdown of balancing costs including the BM in the Monthly Balancing Services Summary (MBSS).

You referenced Blackstart, could you tell us a bit about what that is please?

A black start is the process of restoring an electric power station or a part of an electric grid to operation without relying on the external electric power transmission network to recover from a total or partial shutdown. Blackstart costs are shown in the New BCR report.

BCR Reports: currently there are new and old reports circulating; when will the old ones become redundant and just new ones be circulated?

We are planning to stop circulating the old reports and just circulate the new reports from April next year. We will inform the industry of the plan soon.

TNUoS Tariffs

Are there any plans to produce longer than 5-year TNUoS forecasts?

There is currently no plan to produce a forecast for longer than 5 years unless there are modifications to the CUSC to change this. It is worth noting that the further out a forecast goes the less accurate it becomes, also the charging methodology may change in the interim, which would mean a longer forecast would be of limited value.

Where on the website is the DNO/DCC demand data published?

It is published as part of ETYS appendix G. There is a page dedicated to our T&T model which has links for data inputs, including DNO demand data Here.

If embedded TNUoS liable generation only pays wider tariff and not local tariff, does this mean CMP317 will not impact them apart from the removal of TGR?

There will likely be a lot of alternatives for CMP317, so whilst the intention is to focus primarily on local circuit/substation charges, we can't currently rule out any change to any other part of the Generator TNUoS charge, either for embedded generators or transmission-connected.

Why are published TNUoS tariff forecasts and actuals usually so different?

We endeavour to make the forecast as accurate as possible. However, as the forecast is made based on the information available at the time, it tends to be different from the actuals. We welcome recommendations on improving the content of the forecast report and the accuracy of our forecasts

Are the Tariffs forecasts used by suppliers to pass on charges to their customers for TNUoS?

Unfortunately, this is not a question that the ESO is able to answer.

Where is the debate (TransmiT and Charging reviews etc) now on Locational Marginal or Nodal Pricing?

The TCR, looking at residual charging is due to conclude shortly, with the access SCR, which is considering how granular charges should be at a locational level, concluding in 2023. We're looking at a lot of options across DUoS and TNUoS, although we expect that the methodology underpinning TNUoS locational charges won't change significantly and will still be based on the incremental cost of adding 1MW at different nodes on the network.

Will National Grid ESO consider discounting TNUoS to compensate for the increase in BSUoS due to the Western HVDC link (already baked into TNUoS charges) breaking?

We are not currently considering this. They are two completely different charging mechanisms and have a different customer base.

TNUoS Tariffs - Generation

What if the technologies at co-located sites have the same TEC, how would you pick the dominant technology?

If one technology type has higher TEC, then it is the dominant technology and generation wider tariffs applicable to that technology will be applied. We currently do not have any policy in place on how to treat the site if the TEC for each technology type is the same. CMP316 is looking at co-located sites and how to allocate the costs across both technology types.

What will happen to Generation TNUoS rates after Brexit if UK is no longer subject to EU's €2.50 cap?

Generators in GB will still be subject to TNUoS, and those charges will still have to be within the €0-2.50/MWh range as the European Regulation that sets the range has been adopted into UK Law. Even if there's no deal for Brexit, the regulation will still apply, and it will still be in Euros without an index link.

What is the rationale for year-round not shared, being 100% for intermittent and low carbon but ALF adjusted for conventional carbon?

The ALF adjustment for conventional carbon was introduced by CMP268, which was implemented a few years ago (documents related to this can be found here). The proposer's argument was that such generators (conventional carbon), if behind a highly-congested boundary, do not use the network capacity all the time.

Do generators have to place security for TNUoS charges?

No; generators must secure 29 days of BSUoS charges only.

Is ETUoS always project specific?

Yes, the ETUoS tariff, which is set as part of the offshore local TNUoS tariffs by NGESO at the point of asset transfer of the project, is based on the proportion of capital costs related to connecting to the DNO network for the project in question.

Please note that any enduring distribution use of system charges will be passed through to the relevant generator by NGESO, this is also known as an ETUoS charge.

As I understand it, neighbouring generation zones should have a low difference in charges (<£1). Is it likely these zones will be further split to achieve this?

If we left the methodology unchanged, there would be close to 60 generation zones in the next price control period as the +/-£1 isn't index linked, but even if it were, we'd still end up with significantly more zones than we have today. We've raised CMPs 324 and 325 specifically to look at how to rezone in a way that facilitates generators receiving long-term investment signals, rather than facing changing zones at every price control.

What if there is no generic ALF for a new technology?

For a new technology, which is not on the current list, we would use the category of the closest existing technology. We would welcome any thoughts on how to bring the technology list up to date in the SQSS and CUSC.

Will local circuits be remaining in the TNUoS methodology for the foreseeable future?

Local Circuits and Substations will stay in the methodology – we've raised CMP317 to look at the extent to which certain assets, and specifically the charges for those assets are classed as, "charges for the assets required for connection", and we think that there's a strong argument to say all Local Circuit/Substation Tariffs should be classed that way. Those charges would still be under the TNUoS methodology but would not count towards the cap or collar, if that change is approved.

Can you clarify on the rules for whether generators qualify for the embedded export tariff?

Small and medium non-licensable generators (with a TEC <100MW) are not liable for generation TNUoS charges but may be eligible for Triad payments through the embedded export tariff. The payment associated with exporting over the Triads is paid to electricity supplier unless there is a contract (BEGA/BELLA) in place between National Grid and the generator.

Why is the small generator discount being phased down if it was there to make a level playing field?

The small generator discount has been extended until March 2021. There is currently an ongoing a significant code review by Ofgem to consider what the charging regime should be and is considering making transmission and distribution charging regimes consistent, removing the need for the small generator discount.

Do you have an update on the number of Generation zones there will be from 2021?

The NGESO raised CMP324 to change the way in which the generation zones are currently determined. Under the current methodology, the generation zones will increase from 27 to 60 zones, that's 60 zones to publish for the period starting with the price control. We raised the CUSC modification to simplify it and to align to DNO zones (14) so it gives better investment signals. Various alternatives are expected to evolve, and the final decision will be made by the Authority.

TNUoS Tariffs - Demand

How do you split your demand revenue between HH and NHH when setting tariffs?

It is split by the level of demand we forecast from HH and NHH customers. We have more NHH demand than HH, so the revenue collected from NHH is higher than HH. We calculate how much revenue we expect to be collected through NHH demand then the rest of revenue to be collected will be allocated to HH tariffs.

Are any of the TNUoS tariffs based on metered volume/demand grossed up by line losses?

We do not take into consideration transmission line losses when calculating the TNUoS tariffs.

Why are HH Demand and Embedded Export forecasts in kW but NHH Demand in kWh?

For kW it's a snapshot of a half-hourly triad period, for NHH it is every day of the year over 6 settlement periods (between 4pm and 7pm inclusive) so the tariff is priced in kWh

What does directly connected demand mean - transmission connected? And what happens if generation and demand are co-located on the transmission network?

Directly connected means connected to the transmission network; e.g. a steelworks or other large industrial site. If the node has both generation and demand (e.g. via a Trading Unit) it may be liable for demand charges.

Will HH metered settlement plans change the NHH demand TNUoS charging structure?

Under the Access and Forward-Looking Charges SCR, Ofgem and the network companies are looking at how the non-residual parts of TNUoS and DUoS should be levied. At the moment, smaller NHH sites that migrate to HH are still treated as though they're NHH so as to prevent a move to Domestic consumers being charged at triad for a short period of time, only for that charging regime to change again once the SCR is concluded. The current arrangements are due to end in March 2023, with the SCR changes replacing them taking effect from April 2023.

How do we charge suppliers/What are they based on? Supply forecasts?

Half-Hourly electricity suppliers are charged based on their forecast average gross demand over the three winter peak periods (Triads). Non Half-Hourly is charged based on the supplier's forecast of energy consumption between 4pm and 7pm every day of the financial year. The forecast is reconciled twice against Elexon's settlement metering. The initial reconciliation is in June the year after and the final one is in the Autumn two years after.

How do you apply the residual tariff – is it applied equally across zones?

The residual tariff is part of the demand TNUoS tariff and is applied equally across all zones.

Are you trying to reduce the residual tariff?

There is currently a significant code review run by Ofgem to review the residual charge and how it would be applied.

Can you confirm that we double the kWh value in metering to get kW?

The values in Elexon's settlement metering data are in MWh, and we multiply by 2000 to get a kW value

TNUoS Billing

Do you do any reconciliation for the dispute volume (after RF?)?

We can only reconcile what's in the settlement metering provided by Elexon. We use metering data with the latest run type for Initial Demand Reconciliation (and Generation Reconciliation), and we use RF at the Final Demand Reconciliation, as defined in CUSC.

Do suppliers get penalties if they submit poor forecasting values?

We compare the outturn from the reconciliation against the supplier forecast and that gives us the data for 'forecasting performance error; which is applicable from October of the following year. It forms part of the TNUoS credit calculation (plus a seasonal element). e.g. a supplier that under-forecast by 25% may need to secure 25% of their annual charges in the following year.

Do Embedded Generators need to forecast their export for the Triad periods to get paid?

The CUSC requires the customers to forecast gross HH demand and gross exports plus NHH. It's difficult for us to enforce this part of it as quite often embedded generation offsets demand in a BMU which we may not have the visibility of. When it comes to demand reconciliation we check if there's any export generation and apply the HH tariff against that.

Do you have discussions with customers that grossly over-forecast as well as under-forecast, or is this not ever an issue?

We do monitor customers and advise suppliers if we believe they are over-forecasting, particularly new suppliers.

Connections Charging

What happens with connection assets that change into infrastructure assets?

We are currently reviewing our policy on how the connection assets will be treated if they become infrastructure assets and will update industry if anything changes.

You mentioned the 6% rate of return - any plans to review that? Is it likely to go up or down?

There is a CUSC modification looking at rate of return (CMP306) which was raised by Northern Powergrid DNO. If approved by the Authority, it will take effect in Apr 2020/21 and apply to future charges as usually there's no retrospectivity in charging arrangements. The modification is with the Authority for approval and the Code Administrator Team will email industry once a decision has been reached on the modification. CMP306 has been raised to reduce it but we aren't sure of the likelihood of the modification being approved or rejected at the moment, so can't say whether the rate itself is likely to change.

If you had a live project now will it go down or are you fixed at what you set now?

It depends on how Ofgem want to implement so we can't say for sure at the moment - usually there is no grandfathering or retrospectivity but it's down to Ofgem to make a call on how/when it applies if it's approved.

How was the connection charge rate of return originally determined?

It is set out in the transmission standard licence condition C6.8 that the relevant licensee can recover a reasonable rate of return on the capital from costs of carrying out any works. The current 6% return was determined through an assessment of the cost of capital of the relevant Transmission Licensee and was considered reasonable as it was aligned with a price control assessment of the cost of capital. The 6% rate of return is being reviewed in CMP306.

Presumably the Transmission charges for the connection are dependent on geographic location?

The charges are determined by the transmission owner on how much was spent on works for that connection, including the costs of the assets. Each transmission owner determines the charges for works in their area.

Other

Why is the Transmission System in Scotland at 132kV whereas in England and Wales it is 400kV?

As part of British Electricity Trading and Transmission Arrangements (BETTA) in 2005, it was decided that 132kV lines are generally considered to be transmission lines in Scotland, but distribution lines in England and Wales. This reflects the different function of such lines in the respective areas.

What happens with security payments under SoLR?

Any security lodged with NGESO by the failed supplier is retained to defray unpaid TNUoS/BSUoS invoices. The security is not transferred to the Supplier of Last Resort (SoLR).

How much has been recovered for 20/21

We have not recovered any money for ESO Incentive for 2020/21.

How does CMP311 impact credit?

This looks at the extent to which your previous payment history should be used to determine your level of security. One of the issues we have post legal separation is that we’re no longer part of the TO and are an asset-less business which means our ability to secure against our liabilities is vastly reduced. We are trying to take steps to reduce our potential liabilities as we have a new Licence Condition requirement to have a BBB credit rating, which is made more difficult when we are offering unsecured credit of millions of pounds to Suppliers. We’re mindful that 13 suppliers ceased trading in the last year or so, and if there are any sums outstanding when that happens, the shortfall can end up being passed through to all consumers in later years.

Do you use the words 'demand' and 'consumption' interchangeably?

Demand refers to instantaneous demand over one half-hour. Non Half-Hourly is referred to as energy consumption over a given period.