P402 'Enabling reform of residual network charging as directed by the Targeted Charging Review'

This Assessment Procedure Consultation was issued on 2 December 2020, with responses invited by 15 December 2020.

Consultation Respondents

Respondent	Role(s) Represented
Western Power Distribution	Distributor
E.ON energy solutions Limited.	Supplier
Electricity North West	Distributor
Northern Powergrid	Distributor
Last Mile Electricity Ltd	Distributor
SP Energy Networks	Distributor
Energy Assets Networks Ltd	Distributor
BUUK infrastructure	Distributor
National Grid ESO	System Operator

Phase

Initial Written Assessment

Definition Procedure

Assessment Procedure

Report Phase

Implementation

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Question 1: Do you agree with the Workgroup's initial majority view that the P402 Proposed solution does better facilitate the Applicable BSC Objectives compared with the current baseline?

Summary

Yes	No	Neutral/No Comment	Other
7	2	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	This change, or something like it, is essential for the transmission company to comply with the TCR therefore it better facilitates Objective (a) The efficient discharge by the Transmission Company of the obligations imposed upon it by the Transmission Licence.
E.On	Yes	As the current baseline does not meet the data requirements that NGESO requires in order to calculate TNUoS charges in the data sets received currently, therefore a change to the baseline must be changed in order for NGESO to be able meet its obligations as set out to accurately complete its duties tariff setting and billing requirements once TCR SCR changes take effect in 2022.
Electricity North West	No	(d) Promoting efficiency in the implementation and administration of the balancing and settlement arrangements The proposal, to deliver an NGESO Licence obligation, is very complicated and would see large costs (up to £2 million) being borne by industry parties, when simpler and cheaper options are available.
Northern Powergrid	Yes	We agree with the proposer that, on its own merits, the P402 Proposed solution better facilities Applicable BSC Objective (a) – where NGESO has been directed to implement the TCR. However, we do not agree that it better facilitates Applicable BSC Objective (d), as we believe that the P402 Alternative Solution offers a far more efficient option to deliver the directed requirements, that do not necessarily need to even burden BSC parties. Whilst we are comfortable that the P402 principle is progressed under the auspices of the BSC, the requirements could be equally well-delivered via (e.g.) changes to the DCUSA. As such, we cannot

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Respondent	Response	Rationale
		consider a potential £2m solution to represent an efficient means of NGESO discharging its directed requirement to implement the TCR. Further, it is estimated that it will take 10-12 months to implement (we are unclear if this includes user testing), whereas the P402 alternative solution can be delivered in 3-6 months (with user testing potentially a further two months). The P402 Proposed Solution could therefore potentially take up to nine additional months to implement.
Last Mile Electricity Ltd	Yes	Compared with the current baseline the Proposed solution does facilitate the BSC objectives, specifically Objective a) that it discharges the obligations of the Transmission Company imposed on it by the Transmission Licence.
SP Energy Networks	Yes	Yes we agree that the P402 is better than the current baseline, however we believe that the P402 Alternative solution should be taken forward.
Energy Assets Networks Ltd	No	EAN does not agree with the Workgroup's initial majority view that the Proposed Solution better facilitates the Applicable BSC Objectives. EAN are of the view that Elexon's estimated cost of £1.5-2million to implement the solution is not cost effective or a better solution to the Alternative Solution. The Alternative Solution has significantly reduced system change costs than those required for the Proposed Solution.
BUUK	Yes	We agree with the assessment by the workgroup
National Grid ESO	Yes	We believe that P402 is positive in respect of BSC objectives A & D whilst it is neutral against the other objectives. This is because P402 is a fundamental part of delivering the demand residual element of Ofgem's TCR Direction and so it supports NGESO's obligation to deliver the Direction and the associated benefits to competition that Ofgem have identified.

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Question 2: Do you agree with the Workgroup's initial majority view that the P402 Alternative solution does better facilitate the Applicable BSC Objectives compared with the current baseline?

Summary

Yes	No	Neutral/No Comment	Other
9	0	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	It represents better financial value than the original solution.
E.On	Yes	Please see response to Q1.
Electricity North West	Yes	The Alternative proposal does better meet the objectives as the costs of delivery are much lower and hence more efficient.
Northern Powergrid	Yes	We believe that the P402 Alternative solution better facilitates Applicable BSC Objective (a), for the same reason as the P402 Proposed solution, but that it also better facilitates Applicable BSC Objective (d), as it offers a more efficient solution to enable NGESO to deliver the TCR as directed by the Authority. Costs are provided in response to question 3.
Last Mile Electricity Ltd	Yes	Compared with the current baseline the Alternative solution better facilitates BSC Objective a) as above, and also d) Promoting efficiency in the implementation of the balancing and settlement arrangements. The Alternative solution is more cost efficient.
SP Energy Networks	Yes	Yes we agree that the P402 Alternative solution better facilitates the Applicable BSC Objections compared with the current baseline.
Energy Assets Networks Ltd	Yes	EAN agrees with the Workgroup's initial majority view that the Alternative Solution better facilitates the Applicable BSC Objectives, in that the Alternative Solution has much reduced system change costs than those reported to be incurred by Elexon to support the Proposed Solution.
BUUK	Yes	We agree with the assessment by the workgroup
National Grid ESO	Yes	Please see our response to Q1 as both the Original and Alternative are better than the current baseline.

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Question 3: Do you agree with the Workgroup's initial majority view that the P402 Alternative solution does better facilitate the Applicable BSC Objectives compared with the P402 Proposed solution and so should be approved?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	See above
E.On	Yes	E.ON supports the alterative solution as it offers a significant cost saving in the development, provisioning of the required data sets needed where facilitated through LDSOs, with a projected development cost range of £20K – £35k vs Elexon central system development costs of £1.5Mn-£2Mn. When considering changes that are likely to be directed under Ofgem's Access & Forward-Looking Charges SCR we feel that it is highly likely that the data requirements for TNUoS charging will require a significant overhaul in the next 2-3 years, however the outcome of that SCR is still not yet certain. We feel that both the cost savings and medium term uncertainties around future TNUoS tariff structures mean that the P402 alterative offers much greater benefits to implement as the cost savings to industry and ultimately on consumer bills far outweigh the original solution.
Electricity North West	Yes	The proposed solution is overly complex and costly
Northern Powergrid	Yes	The P402 Alternative solution offers a significantly cheaper and more timely option to ultimately deliver the same outcome as the P402 Proposed solution. Our IT service provider estimates that it would cost around £50-90k, split between all DNOs, to deliver the requirements in full (i.e., including providing the data by charging band). It is estimated that this could reduce to £40-60k to deliver a solution whereby the mapping was done outside of the billing system – whether that be by DNOs or more preferably, by NGESO.

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Respondent	Response	Rationale
		Changes to the billing system, and therefore additional costs, would be required to deliver the P402 Proposed Solution – estimated at £20-35k – therefore, the P402 Alternative solution is, at best, only £5k more expensive, or at worst, £70k more expensive, with regards to the impact on DNO billing systems only. We assume that any resource impact would be absorbed into the current operational headcount and therefore existing costs in both the P402 Proposed and P402 Alternative solution. We believe that this should also hold true for NGESO as well, where it is required to implement a new billing system regardless. Whilst we have concerns that IDNOs may not be fully engaged, and potentially be unaware of the requirements in relation to billing systems, we believe that: (i) such lack of engagement equally puts the P402 Proposed solution at risk (as data needs to be provided regardless); and (ii) the requirements could be delivered via a manual solution outside of billing systems if needs be – albeit we recommend that such intervention be minimal to preserve data integrity etc.
Last Mile Electricity Ltd	Yes	While the Proposed solution facilitates BSC Objective a), the high cost of implementing this solution prohibits the facilitation of BSC Objective d). The significantly lower costs of implementing the Alternative solution therefore better facilitates the objectives of the BSC in promoting efficiency.
SP Energy Networks	Yes	The Alternative solution will ensure that NETSO receive all the required data at the required times at a cost substantially less than the original solution.
Energy Assets Networks Ltd	Yes	EAN does agree with the Workgroup's view that the Alternative Solution does better facilitate the Applicable BSC Objectives when compared to the initial Proposed solution. The costs that would be borne by industry, and ultimately the end-consumer, to support the Proposed solution far outweigh the benefits and intent of the modification and therefore the Alternative Solution should be approved.
BUUK	Yes	We agree with the assessment by the workgroup and their rationale
National Grid ESO	No	We believe the Original is better than the Alternative; our rationale for this described in the

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Respondent	Response	Rationale
		later questions but to summarise, we believe the Original will have a lower total cost to industry and provide additional benefits to industry compared to the Alternative.

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Question 4: Do you agree with the Workgroup that the draft legal text in Attachment A delivers the intention of P402 Proposed solution?

Summary

Yes	No	Neutral/No Comment	Other
7	1	1	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	We agree with the statement above but please note that we do not favour the proposed solution as we think that the alternative is a superior solution.
E.On	Yes	No rationale provided
Electricity North West	N/A	We have not reviewed the legal text as we do not believe this should be progressed
Northern Powergrid	No	We generally agree with the legal text, but that is subject to: (i) changing the number of working days that triggers the submission of data, to that agreed following this consultation; and (ii) determination as to whom is the most appropriate party to map the data from LLFCs to charging bands, to the outcome agreed following this consultation. However, we do not agree that the Billing Report and the Tariff Setting Report should be made available to 'Any Party (on request)'. We believe that this data should only be made available by NGESO, at its risk and discretion, if it is to be made available beyond the provision from distributors to NGESO. The Applicable BSC Objectives are not better facilitated by making this data available, and we do not understand what benefit this seeks to achieve/existing problem it seeks to remedy. We note that relevant definitions (e.g., Final Demand Site and Single Site) reference the CUSC and not the DCUSA. Whilst we are comfortable with this, on the basis: (i) a Final Demand Site needs to exclude interconnections between distribution networks, as defined in the CUSC (and not in the DCUSA); and (ii) the CUSC definitions otherwise reference the relevant definition in the DCUSA (for distribution-connected customers), it should be noted that, in the event the definitions between the CUSC and the DCUSA somehow diverge, distributors will continue to align to the DCUSA and therefore

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Respondent	Response	Rationale
		there is a risk of non-compliance. We consider this to be very low risk. It should be noted that these terms are referenced to the DCUSA in the business requirements, which is in contradiction to the legal text. If definitions are referenced to the DCUSA, it needs to be clear that Final Demand Site excludes interconnections between distribution networks, to avoid double-counting demand (i.e., the demand is ultimately recorded by end user metering, and therefore should be ignored at the interconnection).
Last Mile Electricity Ltd	Yes	No rationale provided
SP Energy Networks	Yes	Yes we agree that the draft legal text delivers the intention of P402.
Energy Assets Networks Ltd	Yes	EAN does agree with the Workgroup's view that the draft legal text delivers the intent of the Proposed solution but do not agree that the solution should be progressed.
BUUK	Yes	No rationale provided
National Grid ESO	Yes	Based on our initial review, we believe the text delivers the intention of the mod.

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Question 5: Are you satisfied that you understand the obligations and interfaces for the P402 Alternative Solution via its Business Requirements in Attachment C, without the addition of formal Alternative Legal Text at this stage?

Summary

Yes	No	Neutral/No Comment	Other
9	0	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	No rationale provided
E.On	Yes	No rationale provided
Electricity North West	Yes	We have been involved in the development of the requirements
Northern Powergrid	Yes	We agree that the Business Requirements in attachment C set out the processes and requirements agreed within the workgroup. We note some differences between this and the legal text (attachment A) in two key instances: (i) the defined terms differ between the two (see response to question 4); and (ii) the number of working days that trigger submission of the data; the legal text says two, whereas the Business Requirements says ten – we appreciate both are in square brackets and we assume that the intention will be to align these.
Last Mile Electricity Ltd	Yes	No rationale provided
SP Energy Networks	Yes	Yes we understand the obligations and interfaces for the P402 Alternative Solution.
Energy Assets Networks Ltd	Yes	Although the Alternative solution will require the circulation of the draft legal text to support the Business Requirements, EAN is satisfied that Attachment C enables EAN to understand the obligations and interfaces for the Alternative Solution.
BUUK	Yes	No rationale provided

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Respondent	Response	Rationale
National Grid ESO	Yes	Yes, we are satisfied that the Business Requirements are sufficiently clear for now.

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Question 6: Do you agree with the Workgroup that there are no other potential Alternative Modifications within the scope of P402 which would better facilitate the Applicable BSC Objectives?

Summary

Yes	No	Neutral/No Comment	Other
9	0	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	No rationale provided
E.On	Yes	No rationale provided
Electricity North West	Yes	LDSOs have the information for their own requirements. We have not identified any other potential solution for NGESO receiving the information it requires.
Northern Powergrid	Yes	Whilst a de-scoped version of the P402 Proposed solution would be a perfectly viable option, where (e.g.) mapping to Charging Bands is excluded, such that it is NGESO's responsibility, we do not believe that any such option would better facilitate the Appliable BSC Objectives than the P402 Alternative solution.
Last Mile Electricity Ltd	Yes	No rationale provided
SP Energy Networks	Yes	Yes we agree.
Energy Assets Networks Ltd	Yes	EAN agrees with the Workgroup's view that there are no other potential alternative solutions within the scope of P402 which would better facilitate the Applicable BSC Objectives.
BUUK	Yes	No rationale provided
National Grid ESO	Yes	We broadly agree that there are no other alternatives within the scope of P402, however we do believe the Original solution could be enhanced based on further information being made available by Elexon and industry. Specifically, the workgroup need to understand the Elexon costs for the Original solution and if/how these could be reduced, for example, if LDSOs did the conversion to bands and Elexon only performed the aggregation. At present, it is difficult to make a like-for-like comparison

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Respondent	Response	Rationale
		between the Original and Alternative to determine the most efficient solution for industry.

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Question 7: Do you agree with the Workgroup's assessment that P402 does not impact the European Electricity Balancing Guideline (EBGL) Article 18 terms and conditions held within the BSC?

Summary

Yes	No	Neutral/No Comment	Other
9	0	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	No rationale provided
E.On	Yes	No rationale provided
Electricity North West	Yes	We are not aware of any impact on EBGL
Northern Powergrid	Yes	We have no immediate reason to dispute the view of the workgroup.
Last Mile Electricity Ltd	Yes	No rationale provided
SP Energy Networks	Yes	Yes we agree
Energy Assets Networks Ltd	Yes	EAN agrees with the Workgroup's view that P402 does not impact the EBGL Article 18 terms and conditions, but in line with our response to the first consultation, noted that the Workgroup considered increased retention provisions under Section U of the BSC could then impact EBGL.
BUUK	Yes	No rationale provided
National Grid ESO	Yes	Yes, we agree with the Workgroup's assessment in this respect.

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Question 8: Do you agree with the Workgroup that data should be aggregated and reported by Charging Band? What are the costs and implications of reporting by Charging Band for your organisation?

Summary

Yes	No	Neutral/No Comment	Other
5	3	1	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	St Clements have estimated the cost of this between £50,000 and £90,000 and this would be split between all the DNO so WPD would pay 2/7ths of that cost so £15k to £26k approx.
E.On	Yes	No impacts identified
Electricity North West	No	For ENWL to provide the information by Charging Band would require changes to the Durabill System. St. Clements Services have indicated that system changes for DNOs are likely to be £50-90k split amongst the licensees so it not material. Additional resource would be required to maintain this data in Durabill is likely to need additional resource estimated at £20k per annum. It would seem better for the NGESO to aggregate LLFC data provided by LDSOs using LLFC to Charging band mapping tables. NGESO have asserted that the costs of doing the aggregation themselves is more expensive but have provided no justification. Activities which can be undertaken by NGESO should be done by them as these requirements are to fulfil their licence obligations and NGESO is merely trying to pass its costs onto others.
Northern Powergrid	No	Distributors invoice based on LLFCs. This is a more granular level of detail; therefore, it is arguably a more future-proof solution to provide this level of information to NGESO. NGESO can then easily aggregate this information to Charging Band, but it will hold a more detailed breakdown as may be needed – (e.g.) it could distinguish between NHH and HH settled LV No MIC customers (depending on how LLFCs are allocated), and between customers connected to the LV network or at an LV substation etc.

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Respondent	Response	Rationale
		Regardless, for NGESO to invoice based on Charging Bands, distributors would need to either: (i) make changes to their billing systems to provide the required data; or (ii) a party would need to manually process the data outside of the billing system. As set out in response to question 3, our IT service provider estimates that it would cost a minimum of £10k more (comparing the low range of providing by both LLFC and by Charging Band), and maximum of £50k more (comparing the low range of providing by LLFC, to the high range of providing by Charging Band), to deliver a report by charging band as opposed to by LLFC. Discounting the possibility that the upper range of costs associated with providing data by LLFC (£60k) can be more expensive than the lower range of costs associated with providing the data by Charging Band (£50k), the cost differential ranges from an increase of 25% (£50k v £40k) to an increase of 125% (£90k v £40k). We do not think this is acceptable given the changes are not required by distributors. The one-off system costs would be split between all DNOs; therefore, our share would be approximately £7-13k. This excludes resource costs associated with testing and on-going delivery, but we assume that these costs will be absorbed within current operational resource levels. On the basis that, NGESO needs a new billing system regardless, and the manual process should not be overly complicated (and could, and should, be automated), we believe that NGESO should be able to absorb these costs likewise. Distributors are required by licence to publish charging statements which include the tariffs that will be applied and the LLFCs that map to that tariff. This will provide the information required to map to Charging Bands, and therefore it is inefficient to place an additional obligation on distributors; whether this be achieved by incurring additional system costs or additional resource burden. NGESO should: (i) do this based on principle – to deliver its directed requirement; and (ii) to save unnecessary system changes and therefore costs. This would arguably be of particular benefit to smaller IDNOs, who may not be engaged in industry

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Respondent	Response	Rationale
		changes and may struggle to absorb additional costs/burdens. This way, the cost/responsibility would be borne by the benefiting party, which we do not think should be lost in considering the appropriate party to carry out the mapping. We would, of course, support NGESO in carrying out this requirement.
Last Mile Electricity Ltd	N/A	We await Impact Assessment from our billing provider on changes required (eg mapping LLFCs to Charging Bands within system for aggregation) and their associated costs.
SP Energy Networks	Yes	The one-off cost which will be shared by the DURABILL LDSO consortium to provide the monthly and annual reports are in the range £50k to £90k. These reports will require to be deployed and tested, which will result in additional one-off internal costs. Please note that these costs assume that it is possible to identify final demand UMS import sites by LLFC.
Energy Assets Networks Ltd	No	EAN does not believe that there should to be a requirement for LDSOs to provide a report by Charging Band. To automate the production of a report to support reporting by Charging Band would require a system change to EAN's billing engine. The estimated cost is expected to be approximately £20,000. However to implement a manual process, although the system costs are significantly reduced, the manual administration required is increased (expected to be one Working Day to collate data and report within timescales). Mapping of Charging Bands to LLFCs is already supported by a licence requirement to publish DUoS charging statements which include the tariffs that will be applied and the LLFCs that map to that tariff. This will provide the information required to allow NETSO to support its obligation without placing an additional obligation on distributors.
BUUK	Yes	This is a much simpler approach. The costs to implement this will be minimal.
National Grid ESO	Yes	We strongly support that data is provided by Charging Band for a number of reasons; 1. It will be more robust if data is processed by LDSOs as a LLFC to Charging Band conversion table needs to be created. Given the Charging Bands are

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Respondent	Response	Rationale
		fixed and LDSOs can create LLFCs at will, it makes most sense if this conversion table was controlled by LDSOs as they will be driving updates to this table. 2. LDSOs are likely to need a conversion table to enact billing by band for DUoS and so it would be duplicating effort if NGESO or a third party were to receive data by LLFC from LDSOs. 3. From discussion in the workgroup, we understand it's largely a marginal cost for LDSOs to do this processing. It would require a significant amount of new processing and cost for a third party to do this which would be more costly for industry compared to LDSOs undertaking this function.

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Question 9: What would be the costs and implications of aggregating and reporting data by Line Loss Factor Class for your organisation?

Summary

Yes	No	Neutral/No Comment	Other
5	0	4	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	St Clements have estimated the cost of this between £40,000 to £60,000 and this would be split between all the DNO so WPD would pay 2/7ths of that cost so £12k to £18k approx.
E.On	N/A	None provided
Electricity North West	Yes	The additional costs would be related to system changes only. St. Clements Services have indicated that system changes for DNOs are likely to be £40-60k split amongst the licensees so it not material.
Northern Powergrid	N/A	As set out in response to question 3, our IT service provider estimates that it would cost (one-off) between £40-60k to provide data by LLFC. This would be split between all DNOs; therefore, our share would be approximately £6-9k. We assume that testing and on-going delivery costs would be absorbed within the business.
Last Mile Electricity Ltd	N/A	Per previous response, we await IA from our billing provider.
SP Energy Networks	Yes	The one-off cost which will be shared by the DURABILL LDSO consortium to provide the data by Line Loss Factor class are in the range £40 t0 £60k. The LLFC data will need to be manipulated by the LDSOs to produce the data in the format required by NETSO. There will also be one-off internal costs to deploy and test these changes. Once more these costs assume that it is possible to identify final demand UMS import sites by LLFC.
Energy Assets Networks Ltd	N/A	To automate the production of a report to support reporting by LLFC would require a system change to our billing engine. However, the change required is the creation of a new report only as the LLFC is already held in the billing engine. The estimated cost is expected to be approximately £500 with a

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Respondent	Response	Rationale
		smaller increase in manual administration, estimated to be 0.5 Working Day.
BUUK	Yes	Costs are unknown on this time for this but it would be minimal.
National Grid ESO	Yes	We strongly believe this data should be provided by Charging Band, however should it be provided LLFC, this will have the following impacts; • NGESO does not deal with LLFCs as it is not used in any CUSC methodology or processes run by NGESO. Providing the data by LLFC therefore transfers the 'conversion risk' to NGESO from LDSOs who are better placed to manage this risk and confirm the conversion has correctly occurred. • This will result in additional system development costs as additional data analytics tools will be needed to check/confirm the LLFC to charging band conversion has happened correctly. • There will also be additional query management and operational costs as there will be additional queries from NGESO to LDSOs compared to providing the data by Charging Band. It's possible/likely NGESO will only be made aware of new LLFCs when they fail to be converted to a charging band by NGESO's systems. This will mean a manual exceptions process is needed to find and correct the LLFC to Charging Band mapping with dialogue with the LDSO. As a result, it would likely cause delay and inaccuracy in billing. This therefore is best managed by the LDSOs at the time they create the LLFC. • As additional, unplanned work will be required to implement a solution that prescribes LLFC data being sent to NGESO which places additional risks to implementing the TCR changes in line with Ofgem's direction.

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Question 10: For the P402 Alternative, do you agree with the Workgroup that each LDSO should provide data within 10 Working Days of receipt of the D0030?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	Once the process and reports are established this would be largely if not completely automated and would be part of BAU.
E.On	Yes	This would seem logical as LDSO's could not produce accurate data until there D0030 is received, processed and DUoS bills have been produced.
Electricity North West	Yes	It was clear in the working group that there is no business need for a tight timescale, however 10 Working Days should not present a major problem.
Northern Powergrid	Yes	To ensure that provision of data avoids one of the primary monthly billing runs, which take place after receipt of the final day of SF for the billing period, we agree that ten days provides a sufficient period to run, validate and provide the data.
Last Mile Electricity Ltd	Yes	10WD from receipt of the D0030 should provide enough time to provide the data..
SP Energy Networks	Yes	The 10 working days should provide the LDSO will sufficient time to gather and provide the data.
Energy Assets Networks Ltd	Yes	EAN believes the provision of data within 10 working days following receipt is achievable as this provides enough time for EAN to process the DUoS invoicing for Suppliers and report to NETSO. However, EAN would like to understand the urgency of the report and why those timescales cannot be extended to e.g. 30 WDs.
BUUK	Yes	This should be a sufficient timeframe.
National Grid ESO	No	NGESO issues TNUoS billing on the 1st day of the calendar month mainly based on suppliers' forecast and generator's TEC. Given the current business requirements, the LDSOs are likely to have all of the previous months data around the 23rd day of the month. With provision of data to NGESO within 2 working days (as per the Original solution), this

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Respondent	Response	Rationale
		means NGESO obtains the data within the same month that LDSOs receive the data. As an example for the month of April, LDSOs will get data for all of April around 23rd May and this is provided to NGESO by 27th May for billing on 1st June. With LDSOs providing the data within 10 working days (as per the Alternative solution), this would mean April's data would not be billed until July. This means; • To mitigate the financial risk this adds to NGESO, we would require Suppliers to secure an additional month of TNUoS liability. This will double the amount current required and so add an additional ~£100m financial security requirement on the Supplier community (individual amounts will vary by Supplier). • An alternative means of mitigating the financial risk on NGESO is to revise the TNUoS Billing process to bill mid-month rather than beginning. This will result in significant disruption to industry cash flows and place a significant risk on ESO cash-flow. This is because NGESO bill TNUoS on the 1st of each month on 14 day payment terms and NGESO are liable to pay all Transmission Owners on the 15th of each month. This requires additional system/process changes and still require the Supplier community to secure an additional half month of TNUoS liability (~£40m) as well as potentially having to invoice Suppliers an extra half-month to ensure the adverse impact on NGESO's cashflow is neutralised. • It disconnects the amount of financial security that is required to be provided by individual Suppliers from the risk they pose, especially Suppliers with rapidly growing or shrinking portfolios. • • Given the reduced number of days in February, LDSOs providing data to NGESO in timescales over 2 working days would mean invoicing on 1st March would not be possible. We accept that 2 working days (under the Original proposal) may be a tough timeframe for LDSOs to provide the necessary data and are open to discuss how this can be relaxed slightly to make it more manageable. We would however note that no LDSO has said that provision within 2 working days cannot be done and the direction of travel within the industry is for data to be provided quicker.

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Respondent	Response	Rationale
		It may be possible to avoid the issues described above, if the billing data was provided at a fixed time of the month that avoided DNO billing cycles (for example, some point between the 15th and 20th of each month) and included all data provided/updated since the last report. This would provide certainty to all parties involved when data was to be provided and what should be included whilst avoiding interactions with existing processes. It would require NGESO to bill based on the snapshot of the latest data provided by this day and Suppliers being accommodating of this.

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Question 11: Will the P402 Proposed Solution impact your organisation?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	See below, the impacts are very similar, however the proposed solution would be potentially more complex as mapping data would have to be provided too. We believe that the proposed solution is unnecessarily complex and expensive solution for what is a relatively simple problem.
E.On	No	Whilst we have indicated no, there is an indirect impact on suppliers as the data the P402 solutions provisions would ultimately inform the TNUoS charges NGESO produce.
Electricity North West	Yes	Primarily running the reports developed by SCS and issuing to NGESO.
Northern Powergrid	Yes	The provision of the reports will incur one-off costs as indicated in responses to previous questions. Whilst we believe that on-going costs can be absorbed in the business, the P402 Proposed solution will place additional requirements to provide this data, including (but not limited to): (i) system testing; (ii) system maintenance (e.g., maintaining a new standing table to map LLFCs to Charging Bands); (iii) report validation; and (iv) updated internal policies and methodology documentation.
Last Mile Electricity Ltd	Yes	Regardless of which solution is implemented, changes will be required to our billing system to extract the required data in the specified format.
SP Energy Networks	Yes	User Acceptance testing of the new reports required by ELEXON. Scheduling and producing these reports and sending them to ELEXON.
Energy Assets Networks Ltd	Yes	EAN will be impacted by the Proposed Solution. EAN would be required to submit HH data to SVAA within 2WDs of receipt (in line with the current drafted legal text). The impact would be on the manual administration required to compile the report and provide to SVAA within those timescales.

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Respondent	Response	Rationale
		EAN would not incur any system costs as our current billing system can support the requirement without a change in functionality.
BUUK	Yes	As an LDSO we will be required to comply with the new obligations as set our in the business requirements.
National Grid ESO	Yes	Yes, P402 will have an impact on NGESO which will be needed to comply with Ofgem's direction. Details of this impact are described in other parts of this response.

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Question 12: Will the P402 Alternative Solution impact your organisation?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	There may be a small amount of CVA data that requires attention for the St Clements solution and setting LLFC to Banding data. In terms of setup there will be initial installation of the St Clements reports etc. and user testing and setting up SFTP links. Once the processes are established we would envisage minimal operational impacts.
E.On	No	See Q9.
Electricity North West	Yes	Impact covered in previous questions.
Northern Powergrid	Yes	The provision of the reports will incur one-off costs as indicated in responses to previous questions. Whilst we believe that on-going costs can be absorbed in the business, the P402 Alternative solution will place additional requirements to provide this data, including (but not limited to): (i) system testing; (ii) system maintenance (e.g., potentially maintaining a new standing table to map LLFCs to Charging Bands); (iii) report validation; (iv) potential manual solution development (internal or supporting NGESO) to map LLFCs to Charging Bands outside of the billing system; and (v) updated internal policies and methodology documentation. We believe that the main difference between the P402 Proposed and Alternative solutions is limited to cost, other than where manual processing to map LLFCs to Charging Bands may be needed, and where this is unfortunately not a consideration of the P402 Proposed solution. For the avoidance of doubt, we do not believe that the mapping of LLFCs to Charging Bands should impact us, other than supporting NGESO in carrying out this activity.

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Respondent	Response	Rationale
Last Mile Electricity Ltd	Yes	Regardless of which solution is implemented, changes will be required to our billing system to extract the required data in the specified format.
SP Energy Networks	Yes	Changes will be needed in the DURABILL application to provide these reports and the LLFC data which will require User acceptance testing. On-going operational impacts are to provide the data as and when required.
Energy Assets Networks Ltd	Yes	EAN will be impacted by the Alternative Solution depending on the format of the report. To provide a report by Charging band would need a system change to our billing engine (please refer to our answer to question 6 above). To report by LLFC will require a simpler change to our billing engine (please refer to our answer to question 7 above). Both options increase the administration required to generate and provide the report to NETSO within the timescales proposed.
BUUK	Yes	As an LDSO we will be required to comply with the new obligations as set our in the business requirements.
National Grid ESO	Yes	Yes, the impacts on NGESO (in addition to the impacts of the Original proposal) are ; • • Since NGESO will require this P402 for charging customers and posting revenue to Group accounts; assurance needs to be provided and SOX control requirements met. Under the Original, this is assurance is gained from one party (Elexon) with whom NGESO has an established relationship. Under the Alternative, this will need to be established with each LDSO – this will add complexity and cost in meeting SOX compliance requirements (such as auditing of LDSOs). • • In the event of an issue with the data, the ESO will need to identify the source of the issue (ESO data handling or in the data provided). This will require additional reporting so NGESO can identify which LDSO to contact to resolve the issue – increasing cost and complexity. • • We anticipate that additional two Full Time employees would be required to deal with LDSO, external Auditor and customers who challenge the data used for billing.

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Question 13: Will your organisation incur any costs in implementing the P402 Proposed Solution? If so, what do you estimate these to be?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	See above Qs 6, 7, 9 & 10, because of its complexity we think that the proposed solution will have more on-going maintenance and therefore costs than the alternative solution. We do not think this is affected by the BSC Systems Release.
E.On	No	Whilst we have indicated no, there is an indirect impact on suppliers as we would expect to receive a proportion of the implementation costs either through BSCCo Costs or through DUoS dependent on the approved solution.
Electricity North West	Yes	We would expect costs to be similar to the alternative solution but may be higher as timescale for response are tighter.
Northern Powergrid	Yes	Please see response to question 3 (and throughout this response).
Last Mile Electricity Ltd	Yes	Per previous responses, costs will be incurred in changes to processes and billing system which are currently being Impact Assessed by our provider.
SP Energy Networks	Yes	The proposed solution would require internal testing and we anticipate the costs would be high. It is not possible to provide costs at this time, more detailed analysis would be needed to determine a cost.
Energy Assets Networks Ltd	Yes	The estimated costs to implement the Proposed Solution is expected to be the cost of additional administration required to collate and provide a report within the timescales required. EAN would not incur any system costs as our current billing system can support the requirement without a change in functionality.
BUUK	Yes	We are unable to detail the costs of the change however changes to our systems will be minimal.
National Grid ESO	Yes	The expected cost to NGESO of implementing the demand residual charges elements of Ofgem's TCR

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Respondent	Response	Rationale
		(i.e. excluding the generation residual and BSUoS changes) with the implementation of P402 Original solution is expected to be approximately £530k. A proportion of this will be dedicated to ensuring that the existing file flows and processes between NGESO and Elexon are updated to obtaining this data.

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Question 14: Will your organisation incur any costs in implementing the P402 Alternative Solution? If so, what do you estimate these to be?

Summary

Yes	No	Neutral/No Comment	Other
8	1	0	0

Responses

Respondent	Response	Rationale
Western Power Distribution	Yes	See above.
E.On	No	See Q11.
Electricity North West	Yes	See response to previous questions
Northern Powergrid	Yes	Please see response to question 3 (and throughout this response).
Last Mile Electricity Ltd	Yes	Per previous responses, costs will be incurred in changes to processes and billing system which are currently being Impact Assessed by our provider.
SP Energy Networks	Yes	Difficult to provide costs, a high level indicative costs would be in the range £30-60k, depending on the level of testing of testing required.
Energy Assets Networks Ltd	Yes	EAN will be impacted by the Alternative Solution (please refer to our answers to question 6 and 7 above). Both options increase the administration required to generate and provide the report to NETSO within the timescales proposed.
BUUK	Yes	We are unable to detail the costs of the change however changes to our systems will be minimal as a lot of the data will be available via our standard report suit.
National Grid ESO	Yes	The costs associated with delivering the Alternative Solution will be additional to values provided in our response to Q11. Based on an indicative Impact Assessment, we expect the Alternative Solution to cost an additional £295k in addition to the Original proposal (£795k in total) to implement. This is excluding any additional ongoing operational costs such as;

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Respondent	Response	Rationale
		• Additional costs associated with SOX compliance controls that will be required (e.g. auditing of LDSO data and processes). • As explained in Q10, two FTEs would be required on an enduring basis to deal with queries regarding the data with LDSO, Auditors and customers.

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Question 16: How long (from the point of Ofgem approval) would you need to implement the P402 Proposed Solution?

Responses

Respondent	Response	Rationale
Western Power Distribution	2-3 Months in addition to St Clements lead time or 3-6 Months	See responses to Qs 6, 7, 9, 10, 11 & 12
E.On	N/A	No rationale provided
Electricity North West	3-6 months	Information provided by SCS. Timescales would be similar for both solutions
Northern Powergrid	~ 4 months	As identified by our IT service provider, the new reports will take around three months to deliver from receipt of approval from the Authority, and we have assumed that we will need two additional months for user testing and applying these changes to the production system.
Last Mile Electricity Ltd	Approx 4 – 6 months	Awaiting impact assessment from billing provider but estimate 4 – 6 months to implement changes, accounting for upgrade to systems, and testing.
SP Energy Networks	N/A	None provided
Energy Assets Networks Ltd	6-8 weeks	EAN would be able to implement P402 within 6-8 weeks following approval of the modification. The October 2021 tariff setting data would require manual processing for the one off exercise, but from April 2022 onwards, EAN will be able to meet the requirements of the Proposed Solution.
BUUK	1 month	The system changes required are minimal, but some changes are required and we are already undertaking a large system change at this time. Therefore the driver for the lead time is to ensure that we have enough time following our own business changes
National Grid ESO	5/6 Months	The ESO are already working to deliver the suite of TCR changes to meet the Ofgem direction, including the changes to the demand residual on the assumption P402 will be approved (i.e. the ESO are working at risk). We are currently on track to meet the timescales directed by Ofgem however we will need a minimum of 5 to 6 months between an

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Respondent	Response	Rationale
		approval of the P402 Original Solution and go-live of the TCR reforms.

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Question 15: How long (from the point of Ofgem approval) would you need to implement the P402 Alternative Solution?

Responses

Respondent	Response	Rationale
Western Power Distribution	1-2 Months in addition to St Clements lead time or 3-6 Months	See responses to Qs 6, 7, 9, 10, 11 & 12
E.On	N/A	No rationale provided
Electricity North West	3-6 months	Information provided by SCS. Timescales would be similar for both solutions
Northern Powergrid	4-7 months	As identified by our IT service provider, the new reports will take between three to six months to deliver from receipt of approval from the Authority, and we have assumed that we will need two additional months for user testing and applying these changes to the production system We believe that implementation would be at the lower end of the range if the data were provided by LLFC, and not by Charging Band.
Last Mile Electricity Ltd	Approx 4 – 6 months	Awaiting impact assessment from billing provider but estimate 4 – 6 months to implement changes, accounting for upgrade to systems, and testing.
SP Energy Networks		St Clements will require 3 to 6 months from when Ofgem approve to the alternative proposal. We will then require a further month to complete user acceptance testing.
Energy Assets Networks Ltd	6-8 weeks	EAN would be able to implement P402 within 6-8 weeks following approval of the modification. The October 2021 tariff setting data would require manual processing for the one off exercise, but from April 2022 onwards, EAN will be able to meet the requirements of the Alternative Solution.
BUUK	1 month	There are next to no system changes required for the alternative solution for BUUK however we are already undertaking a large system change at this time. Therefore the driver for the lead time is to ensure that we have enough time following our own business changes.
National Grid ESO	6/7 months	Please see our response to Q13. The Alternative solution will require additional work to implement

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Respondent	Response	Rationale
		and whilst this is currently achievable in similar timeframes to the Original solution, it has an increased likelihood of taking longer than expected. This therefore places a greater risk on NGESO failing to implement the changes for April 2022 than the Original.

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Question 17: Do you have any further comments on P402?

Responses

Respondent	Response	Comments
Western Power Distribution	No	
E.On	No	
Electricity North West	Yes	These requirements are to assist NGESO in delivering their Licence obligations and they should bear the cost. DNOs would be able to recover some of these costs through the price control mechanism where there is a sharing factor between customers and shareholders. Costs for DNOs are likely to be small. This may not be the case for IDNOs who have no mechanism for cost recovery and the costs may be higher as they may not be using the same system as other DNOs. In theory this could materially impact a number of IDNOs. Whilst using the BSC to specify these requirements may be pragmatic, it is not clear that this actually falls within its scope and an alternative would have been for NGESO to contract directly with LDSOs and fund the costs of meeting their obligations. In order to address this issue, it may be appropriate when this change goes to the Panel and Ofgem is to recommend that should the proposal be approved, LDSOs should be able to recover any material costs from NGESO.
Northern Powergrid	No	
Last Mile Electricity Ltd	No	
SP Energy Networks	No	No further comments.
Energy Assets Networks Ltd	Yes	To reiterate our response to the first consultation, implementing P402 in April 2022 overlaps with a number of other significant industry changes e.g. Faster Switching and MHHS. This may impose additional constraints on resources to meet each programme's implementation date.
BUUK	No	

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Respondent	Response	Comments
National Grid ESO	Yes	have the following additional comments we'd like to make in respect of P402; • We would like it noted that we are strongly of the preference to receive data as soon as possible. We note that the primary limitation in providing this data quicker is the speed of industry data flows. We would hope as part of the various reforms currently under way in the industry that this would be accelerated. • The P402 Original solution provides longer-term benefits to industry compared to the Alternative solution. This is because the 'inputs' and 'outputs' of P402 are separate and it ensures the 'outputs' of P402 are centrally captured so that future industry changes (e.g. Access & Forward Looking Charges, Faster Switching, MHH settlement etc) can be considered if/when the P402 'inputs' change. Under the Alternative solution, this interface is combined and so will need to be fully redone if there are any changes. • The currently identified solutions are the minimum viable solutions for ESO due to restrictions in data provision timescales (i.e. data from the DNOs is not available until the SF settlement run). As part of the industry developments listed in the previous point, we would look to revise when this data is provided so that ESO billing processes can operate closer to real time. There will be benefits of ensuring these industry changes are co-ordinated in a single industry code rather than across multiple codes. • The P402 Original solution enables better provision of data in a transparent way than other methods. Feedback from industry (e.g. Issue 84, P398, P399) has shown market participants prefer industry data to be accessible and centrally located (such as BMRS or the Elexon Portal) rather than scattered across numerous webpages/databases.

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