Question No.	Proforma section	Criteria	Topic	Question	Date question asked	Date response required	Date received	Follow up to Question #	Confidential (y/n)
1	n/a	b) Value for money		Please provide a table with a breakdown of indicative day rates and person days for NG and each project partner. This should be based on the amount of person days required and proposed labour costs.	16 August 2016	18 August 2016	18 August 2016		
2	n/a	b) Value for money		Please provide a description of how the travel and expenses budget has been determined. Please provide a breakdown of these costs if available.	16 August 2016	18 August 2016	18 August 2016		
3	n/a	f) Relevance and timing		Please provide a copy of the analysis undertaken and referred to in the full submission regarding the reactive power currently available from DER	16 August 2016	18 August 2016	18 August 2016		
4	n/a	g) Robust methodology/ready to implement		Please provide the basis for the growth of new DER to the estimate of 3,720MW by 2050.	16 August 2016	18 August 2016	18 August 2016		
5	n/a	g) Robust methodology/ready to implement		Please confirm the target number or volume of response from DER during the trial. If the project has identified a minimum response required for the project to produce meaningful results please also provide this.	16 August 2016	18 August 2016	18 August 2016		
6	various	c) Generates new knowledge		With relation to section 1.2 – Project Description, says TDI 2.0 will resolve transmsmssion voltage constraints. Section 1.4.3 & section 2 – Project Descrition (first paragraph) then refer to it managing multiple constraints. Section 2.1.2 – The problem, then picks up on thermal limitations and also post fault drop in volts. Section 2.2 – technical description of the project, starts by saying TDI 2.0 will focus on… dynamic reactive response and active power management from DER for distribution and transmission constraints. The project objectives seem to vary within these two sections. To help review this submission please provide a concise list and brief description of constraints this project is looking to address, it will be useful if it can be in a tabular format.	23 August 2016	25 August 2016	25 August 2016		
7	2.3.1	c) Generates new knowledge		Please provide a general description & technology types of various DERs which this project is expecting to utilise for provision of intended services to transmission networks.	23 August 2016	25 August 2016	25 August 2016		
8	2.3.1	c) Generates new knowledge		NGET SO is implementing a new state of the art ICT system (EBS) for the electricity markets. Have you looked at the possibilities of integrating the ICT requirements for TDI 2.0 into EBS e.g. as an add on module negating the need for building a seperate platform.	23 August 2016	25 August 2016	25 August 2016		
9	2.3.1	c) Generates new knowledge		ENW's CLASS project is also aiming to provide ancilliary services to the SO by using distribution assets. This arrangement will also need some ICT based command/control between DNO & SO. Have you explored possible synergies between the two? It won't be desirable to have multiple ICT platforms between DNOs/SO, particularly from national roll out perspective.	23 August 2016	25 August 2016	25 August 2016		
10	n/a	b) Value for money		The Full Submission Guidance states 'Enough information should be included in this [NPV] summary so that it can be used in conjunction with the data in the Full Submission Spreadsheet to enable the Panel to independently calculate the Net Present Value of each Method.' Please direct us to where you have provided this information in your submission.	25 August 2016	30 August 2016	30 August 2016		
11	n/a	d) Is innovative		Pleased explain what constraints applied to the forecast of 3,720MW new DER by 2050? Is this based on a linear growth model and does it take into account any flattening off due to constraints and diminishing returns?	08 September 2016	13 September 2016	13 September 2016		
12	n/a	g) Robust methodology/ready to implement		How will intermittency be managed, eg will PVs be able to bid no matter what the forecast is?	08 September 2016	13 September 2016	13 September 2016		
13	n/a	g) Robust methodology/ready to implement		Will the "dispatch" be based on current real power output or how will the available reactive power be determined at any instant.	08 September 2016	13 September 2016	13 September 2016		
14	n/a	g) Robust methodology/ready to implement		What is the intermittency assumption in the analysis of the available reactive power contribution from DERs?	08 September 2016	13 September 2016	13 September 2016		
15	n/a	g) Robust methodology/ready to implement		Please provide a further explanation of the impact of the assumptions on page 92 have been accounted for and their impact the CBA. o (Bullet 1) The assumption that existing DER can be converted to ANM. This is correct but can they be converted for fast response reactive power change. As the incentives are not yet determined, it is not clear if existing generation will choose to convert. o (Bullet 2) That the new mechanisms will encourage connections where they have the most impact. Connections are usually constrained by geography and network capacity, so the flexibility may not be there. Has this been accounted for? o (Bottom of page 92) The assumption that tap-change (TC) control is not installed at most primaries and GSPs and that this increases sensitivity to the solution. Running on fixed taps in a model will improve the sensitivity unless the TC regime is altered to artificially trigger reactive power generation/absorption.	08 September 2016	13 September 2016	13 September 2016		
16	n/a	g) Robust methodology/ready to implement	European interactions	a) To what extent have the project team considered the interactions/compatibility between the design of the TDI 2.0 model, and the arrangements set out in the Electricity Balancing guidelines (alongside any other relevant network codes) and those being developed through Project TERRE and other elements of the cross border trading infrastructure? b) In areas where it is not compatible, have you considered: • How the design would be adjusted to support compatibility? • How the project will feed back into the design of cross border arrangements and network codes which have not yet been approved, where learning indicates that these arrangements may not support efficient market operation?	15 September 2016	20 September 2016	20 September 2016		

17	3	g) Robust methodology/ready to implement	Curtailment arrangements	We would welcome further clarification on the extent to which TDI 2.0 will rely on curtailment of flexible connection customers for DER response vs creating new market arrangements (as suggested on page 27) or payments for constraints (on page 20 it is suggested that NG will have to pay the opportunity cost of any curtailed DG). - To what extent will customers who are already subject to curtailment through ANM schemes be able to participate, and would this involve explicit payments for curtailment? - To what extent would the project lead to increased curtailment of DG through flexible connection arrangements? Would this rise above the estimates of curtailment referred to in the contracts? Alternatively is it envisaged that a new costed approach for managing distribution curtailment will be implemented as part of the project? If so, would this be implemented when used for transmission purposes only or for distribution purposes too?	15 September 2016	20 September 2016	20 September 2016		
18	2	a) Enviro+consumer bens		On page 13 the document describes how the DNO would collect forecasting information from DERs (inc availability, capability and price), will optimise the DNO network, and then will translate the bids into service availability and cost to NGET at the GSPs. o Do you have a view yet on how this response would be offered to NGET? Is it in the form of an aggregate output at GSP, or is it based around offering them individual bids from providers? o Are we right in understanding NGET would procure response directly from DERs, alongside procuring it via the DNO? Would use of the latter have the potential to erode benefits associated the TDI 2.0 model?	15 September 2016	20 September 2016	20 September 2016		
19	n/a	a) Enviro+consumer		What percentage of the DER that exists would you need to participate in TDI 2.0 in order to breakeven?	20 September 2016	22 September 2016	22 September 2016		
20	n/a	g) Robust methodology/ready to implement		What have you learnt from ENWL's CLASS about a DNO providing services to the SO?	20 September 2016	22 September 2016	22 September 2016		
21	n/a	f) Relevance and timing		Have you considered the range of other products that the model could be extended to include in the future? How will you ensure that from the outset, the model is designed in such a way to enable these products to be easily incorporated at the appropriate juncture?	20 September 2016	22 September 2016	22 September 2016		
22	n/a	a) Enviro+consumer bens		Instead of reactive compensation units, could an alternative counterfactual be: The SO/TO procures an operational solution(s) directly from DERs (assuming it remains cheaper than capex solution). DNOs continue to separately procure DER flexibility services to manage their own constraints. SO/DNO expected to compete for these resources to some extent. SO will activate DER resource which inefficiently increases DNO costs. SO and DNO may end up procuring two separate responses when the joint procurement of one might have solved the problem. The TDI 2.0 solution would allow SO and DNO coordinated access to DERs. Do you agree with our characterisation of this alternative counterfactual? We understand that the trial has the potential to benefit both the DNO and the SO/TO, but believe that this is not currently reflected in the CBA?	20 September 2016	22 September 2016	22 September 2016		
23	n/a	a) Enviro+consumer bens		Please explain why you have not identified any Direct Benefits from the project.	20 September 2016	22 September 2016	22 September 2016		
24	Appendix 1	a) Enviro+consumer bens		Please provide an estimate of the potential capacity/carbon/environmental benefits. This should include those associated with any deferred/avoided reinforcement and/or faster/more efficient deployment of DERs.	20 September 2016	22 September 2016	22 September 2016		
25	n/a	a) Enviro+consumer bens		Please revisit Question 23 with respect to the definition of Direct Benefits given in the NIC Governance Document.	27 September 2016	29 September 2016	29 September 2016	23	
26	n/a	g) Robust methodology/ready to implement	European interactions	To what extent do you envisage that active power products procured via 2.0 now and in the future might also be used for frequency management (ie energy balancing)? How would the learnings of the TDI 2.0 project be used to inform development/implementation of project TERRE and the balancing guidelines? For instance, will there be consideration of how DNO needs can inform prequalification procedures, 'unavailable' bid markings, and a common merit order of dispatch (at least for directly activated standard products and specific products) to meet both DNO and TSO needs?	27 September 2016	29 September 2016	29 September 2016	16	
27	3	g) Robust methodology/ready to implement	Curtailment arrangements	The response explains that NGET 'will need to define rules for situations in which local constraints and TDI 2.0 service requests coincide'. What approach is envisaged where a conflict emerges between the needs of the DNO and the SO? How is it envisaged that this would be managed?	27 September 2016	29 September 2016	29 September 2016	17	
28	n/a	a) Enviro+consumer bens		You note in your response to Q22 that 'it is not clear that NGET could feasibly procure reactive power with sufficient precision from DERs without operational modelling by the DNO'. However, in the response to Q18 you state that 'National Grid has a number of established contract frameworks with providers within the distribution network... These services include modulation of real power for frequency control and reactive power for voltage control'. It would be helpful to understand how distributed reactive power services are used currently and how the operational modelling problem is managed. Is there any data NGET can provide us with (even if incomplete) which gives a sense of the costs associated with the current lack of coordination, and the benefits which the TDI 2.0 project could deliver in providing this co-ordination?	27 September 2016	29 September 2016	29 September 2016	22	
29	n/a	a) Enviro+consumer bens		You note in your response to Q28 that 'Based on assessment from MPE during the project we might estimate that 5-10 % of the saving might be attributed to the coordination element.' It would be helpful if you could clarify what is meant by 'the saving' - whether you were referring to a specific element of the saving (eg, the Steady State Voltage Opex saving), or the total project saving. Is there any analysis, such as the MPE analysis mentioned in your response to Q28, that you could provide us with, which helps to clarify the 5-10% figure?	06 October 2016	11 October 2016	07 October 2016	28	

Electricity Network Innovation Competition Full Submission

Supplementary Answer Form

Project: Transmission and Distribution Interface 2.0

Project code	**NGET_TDI 2.0_160816_Q1**	**Question Number**	**1**
Question date	**16 August 2016**	**Answer date**	**18 August 2016**
Submission section question relates to	**Value for Money**		
Topic	**Resourcing costs**		
Question	**Please provide a table with a breakdown of indicative day rates and person days for NG and each project partner. This should be based on the amount of person days required and proposed labour costs.**		
Notes on question			
Answer	Figure 4.5 on Page 24 in the bid submission provides a summary breakdown of indicative day rates and person days for NG and each project partner. Please see table on the next page for additional detail.		

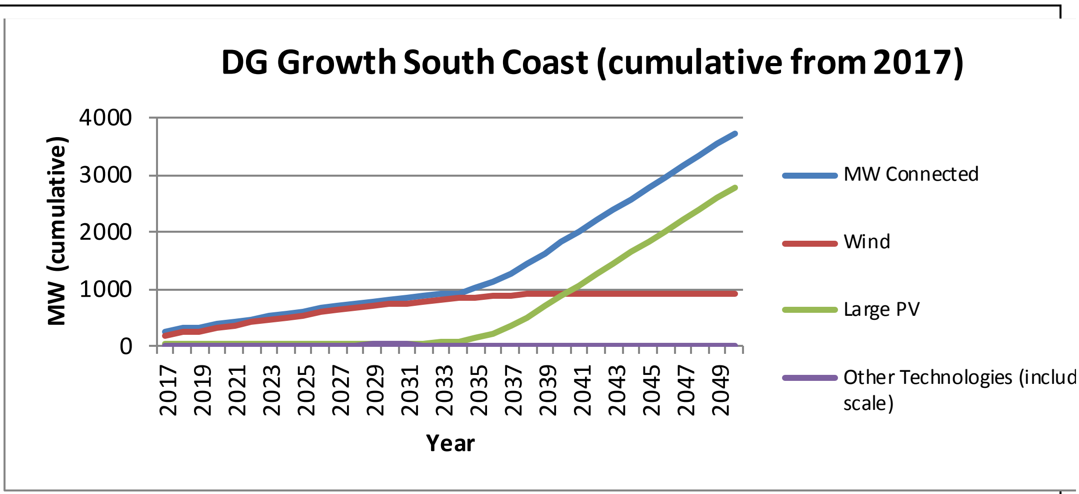
Partner Resources and Rates				
Project Description	**Organisation**	**Rate**	**Total Man Days**	**Total Costs**
Project Resource Costs	**National Grid**	**£ 500**	**628**	**£ 313,750**
	IT PM and Design Authority	£ 500	88	£ 44,000.00
	IT Architecture and Development	£ 500	33	£ 16,250.00
	Business Experts (Access Planning, Control etc.)	£ 500	150	£ 74,750.00
	Commerical	£ 500	332	£ 165,750.00
	Legal	£ 500	26	£ 13,000.00
	Joint Role - Internal	**£ 450**	**1520**	**£ 684,000**
	Project Office	£ 450	390	£ 175,500.00
	CBA	£ 450	117	£ 52,650.00
	Knowledge Dissemination	£ 450	390	£ 175,500.00
	Business Analysis	£ 450	493	£ 221,850.00
	Training	£ 450	130	£ 58,500.00
	UKPN	**£ 400**	**1373**	**£ 549,200**
	IT PM and Design Authority	£ 400	397	£ 158,800.00
	IT Architecture and Development	£ 400	247	£ 98,800.00
	Business Experts (Outage Planning, Control etc.)	£ 400	312	£ 124,600.00
	Commerical	£ 400	358	£ 143,000.00
	Legal	£ 400	39	£ 15,600.00
	Field Technicians	£ 400	21	£ 8,400.00
	Contractor	**£ 600**	**2145**	**£ 1,287,000**
	Project Management	£ 600	780	£ 468,000
	Design Authority	£ 600	286	£ 171,600
	Testing	£ 600	228	£ 136,500
	Commerical	£ 600	429	£ 257,400
	Business Change	£ 600	163	£ 97,500
	Trials	£ 600	260	£ 156,000
Technical Partner Costs	**Technical Partner**	**£ 550**	**2405**	**£ 1,322,750**
	Project Management	£ 750	585	£ 438,750
	Architecture	£ 600	335	£ 201,000
	Functional Expert	£ 500	320	£ 160,000
	Development	£ 400	800	£ 320,000
	Testing	£ 600	205	£ 123,000
	Training	£ 500	160	£ 80,000
Consultants	**Consultants**	**£ 1,450**	**358**	**£ 519,100**
Academia	**Academia**	**£ 513**	**779**	**£ 399,487**
Data Modelling	**Data Modelling Costs**	**£ 900**	**130**	**£ 117,000**
Power Systems	**Power Systems Costs**	**£ 700**	**130**	**£ 91,000**

Project code	**NGET_TDI 2.0_160816_Q2**	**Question Number**	**2**
Question date	**16 August 2016**	**Answer date**	**18 August 2016**
Submission section question relates to	**Value for Money**		
Topic	**Expenses costs**		
Question	**Please provide a description of how the travel and expenses budget has been determined. Please provide a breakdown of these costs if available.**		
Notes on question			
Answer	For the travel and expenses budget, we have used an average rate of 2% of the resource costs for the National Grid and UK Power Networks resources based on previous experience. For the technical IT partner costing, we have used an average rate of 5% based on the information received through the procurement process. We have benchmarked the total expenses budget (1.55% of total project budget) against previous completed projects (Flexible Plug and Play – expenses were budgeted as 1.45% of total, actual outturn was 1.35% of total).		
Attachments			

Project code	**NGET_TDI 2.0_160816_Q3**	**Question Number**	**3**
Question date	**16 August 2016**	**Answer date**	**18 August 2016**
Submission section question relates to	**Appendix 6 – Techical Description**		
Topic	**Techical Description**		

Question	**Please provide a copy of the analysis undertaken and referred to in the full submission regarding the reactive power currently available from DER**
Notes on question	
Answer	Please find attached the results of the report demonstating the reactive power currently available from DER.
Attachments	Copy of report "Question 3 Report Results"

Project code	NGET_TDI 2.0_160816_Q4	Question Number	4
Question date	16 August 2016	Answer date	18 August 2016
Submission section question relates to			
Topic			
Question	Please provide the basis for the growth of new DER to the estimate of 3,720MW by 2050.		
Notes on question			
Answer	As part of its ED1 Business Planning process, UK Power Networks developed a forecasting model to understand the change in load taking into consideration various scenarios for: • Population growth • Energy efficiency improvements in the domestic and commercial/industrial sectors • Uptake of a broad range of low carbon technologies These scenario inputs were informed by a combination of historical trends, government projections and Element Energy models of the uptake of energy efficiency measures and low carbon technologies. These models forecast the impact of differing assumptions regarding the financial incentive regimes, rate of technology cost and performance improvements and energy costs on the rate of uptake. The model has then been developed integrating far more granular consumer data and the key policy changes up to date. In autumn 2015, a further update of the model was undertaken to incorporate smart meter and low carbon technology data from the Low Carbon London trials and update the low carbon technology uptake forecasts to reflect the most up-to-date policy and technology data. The results of the model described the DER uptake for each license area on UKPN per technology up to 2050. For the purpose of the TDI 2.0 project, it was necessary to scale down the DER uptake of the SPN region to the South East. It was established that the current proportion of DER in TDI Project Area in comparison with the SPN region was 70%. Therefore, the results of the complete SPN model were scaled accordingly for the project to use in the CBA calculations.		

	 From the analysis of the model the main driver for the growth is a rise of the PV uptake. In summary, the TDI Project Area is projected to see an additional 550MW of DG by 2030, an additional 1GW of growth between 2030 and 2040 and 1.89GW of additional connections between 2040 - 2050 leading to a total of 3.7GW of DER connections in the area.
Attachments	

Project code	**NGET_TDI 2.0_160816_Q5**	**Question Number**	**5**
Question date	**16 August 2016**	**Answer date**	**18 August 2016**
Submission section question relates to	**Benefit Tables – Appendix 1** **Technical Description – Appendix 6** **Cost Benefit Analysis – Apeendix 10**		
Topic	**Cost Benefit Analysis** **Technical Description**		
Question	**Please confirm the target number or volume of response from DER during the trial. If the project has identified a minimum response required for the project to produce meaningful results please also provide this.**		
Notes on question			

Answer	The target volume of response from DER during the trial is 130MVAr, which can be obtained from 400MW generation. Minimum response required: Our assumption on the minimum reactive power requirements are based on the following logic: On the National Grid network we expect to be able to see changes of 10MVAR at one Grid Supply Point (GSP). The study analysis gave a typical sensitivity factor between MVAr in distribution and transmission network as 2.5, which means 25MVAr (10 x 2.5) of reactive power in the distribution network per one GSP. With four GSPs we assumed minimum requirement to be 100MVAr (4 x 25). Therefore we believe assumption of 130 MVAr is a realistic assumption in comparison to minimum requirements.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**6**
Question date	**23.08.2016**	**Answer date**	**25.08.2016**
Submission section question relates to	**Section 2**		
Topic	**Project Description – Section 2**		
Question	**With relation to section 1.2 – Project Description, says TDI 2.0 will resolve transmission voltage constraints. Section 1.4.3 & section 2 – Project Description (first paragraph) then refer to it managing multiple constraints. Section 2.1.2 – The problem, then picks up on thermal limitations and also post fault drop in volts. Section 2.2 – technical description of the project, starts by saying TDI 2.0 will focus on… dynamic reactive response and active power management from DER for distribution and transmission constraints.**		

	The project objectives seem to vary within these two sections. To help review this submission please provide a concise list and brief description of constraints this project is looking to address, it will be useful if it can be in a tabular format.
Notes on question	
Answer	The constraints and associated services are presented in the table below.

Constraints	Services
High/rising volts on transmission system	Voltage control from Distributed Energy Resources supplementing transmission connected reactive power sources absorbing reactive power as a dynamic response to high/rising voltage
Post Fault voltage collapse on SE transmission system following the loss of Canterbury/Cleeve Hill-Kemsley transmission route.	Voltage control from Distributed Energy Resources supplementing transmission connected reactive power sources injecting reactive power as a dynamic response to low/falling voltage
Thermal constraints	Active power (MW) re-dispatch of distribution connected Distributed Energy Resources to meet distribution constraints with excess capability offered to assist SO management of transmission constraints.

Attachments	N/A

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**7**
Question date	**23.08.2016**	**Answer date**	**25.08.2016**
Submission section question relates to	**Section 2** **Appendix 6**		
Topic	**Project Description – Section 2** **Technical Description – Appendix 6**		
Question	**Please provide a general description & technology types of various DERs which this project is expecting to utilise for provision of intended services to transmission networks.**		

Notes on question	
Answer	As part of the bid submission preparation, National Grid carried out an initial Expression of Interest (EOI) for commercial services from aggregators. UK Power Networks carried out a similar EOI for its customers and interested parties via its website, mailing list and customer engagement forum. The table below provides a summart of the DER providers that we have engaged and have resources in the project area:

Technology / Provider	General Description
Aggregators	We had interest from number of aggregators: Limejump, Flexitricity, Kiwi Power, Ameresco, Reactive Technologies, Enernoc and Restore. Their portfolios include of CHP, land filled gas, solar farms, wind and battery storage. See Letters of Support in Appendix 11 of the main bid submission document.
Solar farms	We met with Lightsource and Foresight Group, the two biggest solar providers in UK. Both are interested and in principle have installations in the area where only minor changes in their control system are required to allow service provision. See letter of support Appendix 11.
Wind generation	Interest has been expressed by embedded wind farms within the area which are relatively large and have the potential to provide a voltage control service from a technology perspective but are not subject to Bilateral Agreements to National Grid. These are Kentish Flats Extension and Little Cheyne (LEEMPS).
Synchronous generation	We have an interest from small CHP and CHP sites from the previously mentioned aggregators.
Storage (including battery storage)	Storage is expected to be a major player in the future energy mix. There are currently 94MW of accepted offers and 65MW of further storage connection enquiries in the South Coast. We engaged with several storage developers which include Elgin (PV and storage), Arenko Cleantech (battery storage), Solarcentury (PV and storage). One of Arenko's projects is currently in construction and expected to be operational in 2017. Aggregators are also developing storage projects that could provide services.

With the above described level of initial engagement with different DER technologies, we expect to have a representation of most of these during the trial phase.

Attachments	N/A

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**8**
Question date	**23.08.2016**	**Answer date**	**25.08.2016**
Submission section question relates to	**Section 2** **Section 6**		
Topic	**Technical Description - Section 2** **Project Readiness - Section 6**		
Question	**NGET SO is implementing a new state of the art ICT system (EBS) for the electricity markets. Have you looked at the possibilities of integrating the ICT requirements for TDI 2.0 into EBS e.g. as an add on module negating the need for building a seperate platform.**		
Notes on question			
Answer	The EBS system is in the final stage of its delivery so at this stage National Grid does not believe it is practical or feasible to alter the specification of the project without detrimental impact. Given the critical nature of EBS, we would only interact with the demonstration project in a very controlled manner. The TDI 2.0 functionality (determination of active/reactive flows, technical and economic optimisation at distribution level) relies on the distribution network information and data that are currently available in DNO systems. The trial will test the proposed architecture and inform the requirements for a national rollout.		
Att achments			

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**9**
Question date	**23.08.2016**	**Answer date**	**25.08.2016**
Submission section question relates to	**Section 6**		
Topic	**Project Readiness – Section 6**		
Question	**ENW's CLASS project is also aiming to provide ancilliary services to the SO by using distribution assets. This arrangement will also need some ICT based command/control between DNO & SO. Have you explored possible synergies between the two? It won't be desirable to have multiple ICT platforms between DNOs/SO, particularly from national roll out perspective.**		
Notes on question			
Answer	In the CLASS project, reactive power absorption is achieved by a technique known as "tap stagger" of primary transformers which in some areas of the UK Power Network's (UKPN) area is already in use. The CLASS method is focused on response from DNO assets and it is primarily a technical interface. The TDI project, the method is based on response from DER assets which have dynamic technical and commercial behaviour and therefore the complexity / functionality of the system is significantly more extensive. DNOs have currently separate and different ICT systems i.e. their Distribution Management Systems. Future architecture could include separate systems (DMS, Forecasting, Optimisation, Scheduling) and common systems such as flexibility services platforms.		
Attachments	N/A		

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**10**
Question date	**25 August 2016**	**Answer date**	**30 August 2016**
Submission section question relates to	**Appendix 10 – Cost Benefit Analysis**		
Topic	**Cost Benefit Analysis**		
Question	**The Full Submission Guidance states 'Enough information should be included in this [NPV] summary so that it can be used in conjunction with the data in the Full Submission Spreadsheet to enable the Panel to independently calculate the Net Present Value of each Method.' Please direct us to where you have provided this information in your submission.**		
Notes on question			
Answer	Please see attached word document "Input data for Calculation of NPV "		
Attachments	Please see attached word document "Input data for Calculation of NPV "		

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**11**
Question date	**08.09.2016**	**Answer date**	**13.09.16**
Submission section question relates to	**N/A**		

Topic	**N/A**		
Question	**Pleased explain what constraints applied to the forecast of 3,720MW new DER by 2050? Is this based on a linear growth model and does it take into account any flattening off due to constraints and diminishing returns?**		
Notes on question			
Answer	As part of its ED1 Business Planning process, UK Power Networks developed a forecasting model to understand the future changes in load and generation. These scenario inputs were informed by a combination of historical trends, government projections and Element Energy models of the uptake of energy efficiency measures and low carbon technologies. The determination of the DG growth in the South Coast was not influenced by technical constraints in the transmission or distribution networks. They were based on market constraints and drivers which will influence the uptake or growth of particular technologies in the area. The model was non-linear and it was based on economic models previously developed by Element Energy. The growth model contains several sets of uptake scenarios to predict the technology uptake, primarily of PV and Wind. These scenarios were based on current technology incentives (such as Feed in Tariffs and Contract for Difference (CfD) schemes) and incorporate policy changes that had occurred recently including the reduction of Feed in Tariff support policies and uncertainty of policy decisions after 2020. Beyond this year there is uncertainty on continued financial support for renewables, thus the decisions from the model were based on economic models and market scenarios. The market scenario used for the DER uptake for the TDI 2.0 project was a high growth market scenario which includes consumer willingness to pay, decrease in technology capex costs, high electricity costs (benefiting generation) and high future strike prices. For more information on the assumptions, the Element Energy Load Growth Model report has been included.		
Attachments	Element Energy Load Growth Model – Update on assumptions and definition of scenarios.		
Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**12**
Question date	**08.09.2016**	**Answer date**	**13.09.16**

Submission section question relates to	**Appendix 6 – Project Description**
Topic	**Dynamic Voltage Control**
Question	**How will intermittency be managed, e.g. will PVs be able to bid no matter what the forecast is?**
Notes on question	
Answer	The TDI 2.0 project will address this issue by incorporating processes within the ICT solution as follows: The ICT solution will receive commercial bids (including their updated forecast of reactive and active power capability) that the DER in the system has submitted. National Grid already has its own forecasts for wind and solar generation power outputs that can be incorporated in the solution. The first check the solution will make will be to compare bids against the declared capability of the DER. If, for example, a DER declares an availability which is over their declared capacity, it will be flagged up and rejected. This capacity check will also include whether or not a particular technology can produce reactive power regardless of their active power output (e.g. PV at night). This comparison will be programmed to address conflicts in forecasted DER output based on weather data versus the declared availability of the participant. Some of the technologies used, particularly by PV inverters, are able to generate or absorb reactive power whether or not the solar panels are generating real power. The solar power companies (refer to Appendix 11 of bid document) we met with are particularly keen to sell reactive services at night when they are of course unable to earn income from power generation. Furthermore, in Appendix 6 (page 68) we have addressed how the commercial framework will deal with bids from participating DER in the event of a non-delivery of services. DER will be discouraged from submitting bids they are not confident of delivering through penalties being borne by the DER in any event in which they fail to deliver contracted services. However, there is a balance to setting these penalties such that they don't discourage intermittent DER from participating entirely. Intermittent technologies could have technologies where their reactive power output is a function of their active output and thus dependant on weather conditions and outside of the DER's control. This results in an uncertainty of volumes bid into the tender process. It is proposed to allow DER to offer an availability level, which reflects the average level they must achieve over the tender period. However, if this

	average level has not been achieved, a penalty payment would be imposed. This comparison between deliveries and the contracted (bid) volumes will be explored as part of the trial with the goal of finding a fair approach that is inclusive of all technology types and that encourages investment in intermittent DER to provide a more reliable service to the system.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**13**
Question date	**08.09.2016**	**Answer date**	**13.09.16**
Submission section question relates to	**N/A**		
Topic	**N/A**		
Question	**Will the "dispatch" be based on current real power output or how will the available reactive power be determined at any instant.**		
Notes on question			
Answer	The TDI 2.0 control solution will have the information regarding technological capabilities of each participating DER (including if their active power output is related to their reactive power one or not). Besides the capability information, the control solution will have forecasting information to be able to feed into an optimal power flow module within the solution to calculate the services availability at GSP level. The availability at GSP level will be calculated constantly (minimum half hourly) by using a combination of the forecasted data, bid costs and level of DER availability, system configuration and contingency analysis. An important clarification is that the participating DER will be required to have voltage droop control and to be able to change the target of the droop remotely via the TDI 2.0 control solution. For further explanation of this control please refer to "Voltage Droop control" Appendix 6, page 61. If a service is to be dispatched (with the exception of dynamic voltage support which is an automated response), the ICT solution will calculate the voltage target droop that each DER will need in order to achieve a certain level of response at the GSP. Therefore, for reactive power absorption, the dispatch signal sent to the DER will not be based on amount of MVAr, but on		

	change of their voltage droop settings, which will result in the calculated MVAr response. If a certain DER technology will be required to lower their active power output in order to achieve that, it will have to be done by each DER's control. For those technologies, the reactive power utilisation bid would reflect the cost of adjusting the active power output in order to deliver the reactive power. In practice this is likely to involve the DER curtailing their active power output. This will result in a large utilisation bid to cover the forgone wholesale price and subsidy revenues. It is unlikely that such a bid would be competitive and is therefore unlikely to be seen in practice.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**14**
Question date	**08.09.2016**	**Answer date**	**13.09.16**
Submission section question relates to	**N/A**		
Topic	**N/A**		
Question	**What is the intermittency assumption in the analysis of the available reactive power contribution from DERs?**		
Notes on question			
Answer	Some of the technologies used by DER have inverters which can change their reactive power output regardless of their active power one. Inverters are the same technology as used in reactive compensation devices such as statcoms which (depending on their technology) are able to support a reliable reactive power output even with a is highly intermittent source (such as wind or PV). The CBA analysis assumes a period of time when the voltage constraint is active in the SE transmission network. The voltage constraints are active when there are high power flows on the transmission network. This high power flow results from the combination of high generation from DER and large power flows on interconnectors. So when the DER is at low output the amount of power flow on the transmission network is low and the dynamic voltage constraint is not active. Therefore the intermittency of the reactive power from DER is reflected in the CBA assumptions by the period when the voltage constraint is active.		
Attachments			

Project code	**NG_UKPN_TDI 2.0**	**Question Number**	**15**
Question date	**8 September 2016**	**Answer date**	**13 September 2016**
Submission section question relates to	**Appendix 6 – Project Description**		
Topic	**Dynamic Voltage Control**		
Question	**Please provide a further explanation of the impact of the assumptions on page 92 have been accounted for and their impact the CBA.** **o (Bullet 1) The assumption that existing DER can be converted to ANM. This is correct but can they be converted for fast response reactive power change. As the incentives are not yet determined, it is not clear if existing generation will choose to convert.** **o (Bullet 2) That the new mechanisms will encourage connections where they have the most impact. Connections are usually constrained by geography and network capacity, so the flexibility may not be there. Has this been accounted for?** **o (Bottom of page 92) The assumption that tap-change (TC) control is not installed at most primaries and GSPs and that this increases sensitivity to the solution. Running on fixed taps in a model will improve the sensitivity unless the TC regime is altered to artificially trigger reactive power generation/absorption.**			
Answer	• (Answer to bullet 1) In our CBA analysis we assumed that all the DER generation will be responding to the voltage change. However, we are expecting that our dynamic studies will determine how fast the dynamic response will need to be. National Grid has considerable experience with traditional synchronous generation technology, wind generation technologies and has met with solar PV companies while preparing this project. The majority are capable of providing voltage control but some changes in control, systems may be required and funded as part of the trialling. • (Answer to bullet 2) The flexibility of the DER based on their contribution has been taken into consideration. As per information on page 92 our initial network analysis suggests the sensitivity, on average, of the transmission network constraints to existing DERs ranges from 40% to 83%. For the purpose of this CBA we have assumed a general sensitivity of 67% on the understanding that the TDI project will encourage new DER connections in areas where they are more effective.			

	(Answer to bullet 3) The reactive power effectiveness assumed for constraint management used for the CBA were based on the study results from M.P.E. The dynamic reactive power responses from the DER within the distribution network were based on simple voltage droop control from local voltage changes. Two time phases were studied, the initial step change in transmission voltage and the position taking into consideration the impact of network tapchangers re-tapping in response to the event. As the question states the actions of the tapchangers does reduce the effectiveness of the DER reactive output as seen at the Grid Supply Point a short time after the initial step change in transmission voltage. The effectiveness used in the CBA was the lower figure following network tapchanger action. Higher effectiveness can be achieved by post fault modification of the voltage set point on both the participating DER and network transformer tap controllers, this is one of the innovation areas of the project.
Attachments	

Project de	**NGET_UKPN_TDI.20**	**Question Number**	**16**
Question date	**15 September**	**Answer date**	**20 September**
Submission section question relates to	**Section 6, Project readiness**		
Topic	**Robust methodology/ready to implement**		
Question	**a) To what extent have the project team considered the interactions/compatibility between the design of the TDI 2.0 model, and the arrangements set out in the Electricity Balancing guidelines (alongside any other relevant network codes) and those being developed through Project TERRE and other elements of the cross border trading infrastructure?** **b) In areas where it is not compatible, have you considered:** **• How the design would be adjusted to support compatibility?** **• How the project will feed back into the design of cross border arrangements and network codes which have not yet been approved, where learning indicates that these arrangements may not support efficient market operation?**		
Notes on question			
Answer	a.) We are considering that the TDI 2.0 model is compatible with existing code arrangements set out in Balancing guidelines, Grid code and SQSS NETS and other relevant codes in other European projects. b.) During the development process of the TDI 2.0 the project team will constantly monitor the progress and changes for the existing and new code arrangements. In the case of the potential changes the project team will discuss changes with code governance body to ensure compatibility is achieved and the necessary code changes are made.		

Attachments	

Project code	**NGET_UKPN_TDI.20**	**Question Number**	**17**
Question date	**15 September**	**Answer date**	**20 September**
Submission section question relates to	**Section 6, Project readiness**		
Topic	**Robust methodology/ready to implement**		
Question	**We would welcome further clarification on the extent to which TDI 2.0 will rely on curtailment of flexible connection customers for DER response vs creating new market arrangements (as suggested on page 27) or payments for constraints (on page 20 it is suggested that NG will have to pay the opportunity cost of any curtailed DG).** **- To what extent will customers who are already subject to curtailment through ANM schemes be able to participate, and would this involve explicit payments for curtailment?** **- To what extent would the project lead to increased curtailment of DG through flexible connection arrangements? Would this rise above the estimates of curtailment referred to in the contracts? Alternatively is it envisaged that a new costed approach for managing distribution curtailment will be implemented as part of the project? If so, would this be implemented when used for transmission purposes only or for distribution purposes too?**		
Notes on question			
Answer	Under current arrangements, newly connecting DERs are responsible for so-called "shallowish" reinforcement required as a result of their connection to the network. Under flexible (ANM) connections these DERs have the option to reduce those reinforcement costs in exchange for accepting some degree of curtailment, where such curtailment is required because of the constraint that they would otherwise have to pay to alleviate. DERs only face curtailment where that specific constraint is binding (and subject to the agreed principles of access, pro-rata currently in the case of South East). Such customers will indeed be able to participate in TDI 2.0. From the point of view of the DER, they may face curtailment events at various points during the year: 1. Those that reflect the local Distribution constraint defined in their connection agreement		

	2. Those that are for services defined under TDI 2.0 This relies on the ability of the TDI 2.0 system to distinguish between these events and provide settlement accordingly. We will need to define rules for situations in which local constraints and TDI 2.0 service requests coincide. In addition, UKPN is proposing to trial a new mechanism that will improve on the efficiency seen under the current LIFO / Prorata schemes (Bullet 1 above). This is being designed to be compatible with existing flexible customer arrangements and will be more aligned with the approach proposed for TDI 2.0 in that curtailment will be based on market signals. Under this new improved approach, DER customers will still receive curtailment estimates based on prorata principles of access. UKPN will then deliver the actual curtailment optimising technical (sensitivity to resolving constraints) and economic parameters (DG willingness to be curtailed) resulting in an overall system efficiency. A methodology to settle amongst participants against the baseline curtailment will then be created. More detail on this work (ongoing currently under NIA) has been provided on the next page. This approach will be used only for distribution purposes. In summary, we are looking to introduce improved market based methodology for allocating distribution level constraints. This methodology is then more aligned with the methods for provision of active and reactive power services to the SO (the TDI2.0 services). <u>More detailed description of the current vs market based curtailment logic under flexible connections</u> For the proposed update to UKPN's existing flexible connections, the underlying principles of access are the same as under LIFO or pro-rata (we assume pro-rata for clarity in this explanation): • Assume that three DG units are positioned behind a local network constraint, and that for the next hour this constraint requires 1MW of curtailment to avoid a breach • Under pro-rata each of these would be curtailed equally to achieve that 1MW reduction; however, because of the network topology there is not a 1:1 relationship between power reduction at the DG site and at the constraint, so more than 1MW of DG curtailment would be expected • Under the new market approach, the cost of curtailment per DG and the sensitivity of each DG to the constraint would be taken into account, and the cheapest curtailment option would be chosen. This may, for example, involve curtailing just one DG if it faces the lowest opportunity cost or is closest (topologically) to the constraint • Based on the cost of curtailment, the other two DGs would then pay the first DG such that its lost revenues (wholesale power, embedded benefits, carbon subsidy) are at least compensated. • Because of the increased economic efficiency of this curtailment approach, there will be a surplus available (it costs less for the 2 DGs to compensate the first than to curtail all three equally). This surplus can be shared between the DG units equally or via some weighting, or can be shared with other system stakeholders such as consumers. This is yet to be determined.

	• Under this approach, other DER technologies will be able to offer to act as "curtailment proxies". For example, a DER aggregator can offer to increase demand. Provided the bid is low enough and the location suitable, this may be a cheaper solution. Now, the original three DERs would pay the DER according to its bid. Note, the presence of the DER can never increase costs for the DG units provided their own curtailment bids are cost-reflective.
Attachments	

Project code	**NGET_UKPN_TDI.20**	**Question Number**	**18**
Question date	**15 September**	**Answer date**	**20 September**
Submission section question relates to	**Section 4 – Benefits, Timeliness and Partners**		
Topic	**Enviromental and consumer benefits**		
Question	**On page 13 the document describes how the DNO would collect forecasting information from DERs (inc availability, capability and price), will optimise the DNO network, and then will translate the bids into service availability and cost to NGET at the GSPs.** **o Do you have a view yet on how this response would be offered to NGET? Is it in the form of an aggregate output at GSP, or is it based around offering them individual bids from providers?** **o Are we right in understanding NGET would procure response directly from DERs, alongside procuring it via the DNO? Would use of the latter have the potential to erode benefits associated the TDI 2.0 model?**		
Notes on question			
Answer	In the TDI 2.0 the reactive power response provided by DER will be offered on an equivalent aggregate basis to National Grid at the GSP. This could be considered as a Virtual Power Plant concept at the GSP. National Grid has a number of established contract frameworks with providers within the distribution network. The frameworks include Mandatory Service Agreements with Large power stations (under Grid Code classifications and CUSC) and commercial services from Aggregators, smaller generators and demand side suppliers. These services include modulation of real power for frequency control and reactive power for voltage control.		

	DNO also has contractual arrangements with generators within their own network. For the purpose of the specific trial and in order to deliver the learning outcomes and test the commercial framework, TDI 2.0 reactive power response will be procured and contracted via the DSO route to market. The volumes and exact contractual strategy will be taken into account as part of the detailed commercial design. We envisage that this approach will be aligned with National Grid procurement strategy and the SO will retain the right to procure reactive power response directly from DERs. We believe this approach and its detailed analysis will inform an optimal whole system approach and maximise the benefits for the consumers.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**19**
Question date	**20 September**	**Answer date**	**22 September**
Submission section question relates to			
Topic	**Enviromantal and consumer benefits**		
Question	**What percentage of the DER that exists would you need to participate in TDI 2.0 in order to breakeven?**		
Notes on question			
Answer	The percentage of the existing DER that would be required to participate in TDI 2.0 breakeven analysis presented on page 94 in Table 1 is 52%.		
Attachments			

Project code	**NGET_UKPN_TDI.20**	**Question Number**	**20**
Question date	**20.09.2016**	**Answer date**	**22.09.2016**
Submission section question relates to	**N/A**		
Topic	**g) Robust methodology – Ready to implement**		
Question	**What have you learnt from ENWL's CLASS about a DNO providing services to the SO?**		
Notes on question			
Answer	ENWL's CLASS has successfully demonstrated the ability to deliver a suite of services which ultimately result in benefits to the end consumer as reduced cost of balancing services. This end result was achieved by developing synergies between the SO and DNO to create and potentially deliver these services without detriment to customers connected in their network. The key learning points from CLASS regarding DNO providing service to the SO are as follows: • A clear regulatory funding framework on how costs and benefits from distribution-procured services would be treated. It was concluded that services procured from DNOs by National Grid (SO) for the purposes of distribution network voltage and network management should be included in the catergory of Directly Remunerated Services 8 (DRS8). This means that DNOs will be incentivised to provide the services and that their customers will benefit by sharing any net revenue received by DNOs for these services. • The project provided results that proved the concept that services procured from the distribution network can be translated into tangible benefits at the interfase point with the SO (GSP). • Has proven that ICCP links between DNOs and National Grid, previously used for data exchange, can be used to provide control functionalities to instruct services procured from distributed resources. This will be instrumental in the TDI 2.0 service procurement. • DNO providing services to the SO can significantly reduce system balancing costs. This is achieved by displacing more expensive Balancing Service providers and assuming that once displaced, these providers will no longer operate (at least in the same operating regime). The project provided further studies on how the system balancing cost reduction will be a function of the DNO services pricing structure.		

	• The above cost reduction coupled with the DRS8 funding mechanism mean that there will be lower use of system charges which will benefit consumers. These reductions can be accomplished as follows:
	  o Direct savings of BSUoS – as the cost of system balancing reduces with the displacement of more expensive market providers, these savings are direcly passed to consumers bills.
	  o Savings in Distribution Use of System (DUoS) charges. This is achieved in the context of sharing DNO revenues from the services with the consumers via the DSR8 framework.
	
	CLASS has also started an industrywide conversation around how can the SO best procure services from DNOs which have unique characteristics and may vary depending on the locational needs of the system. This topic revolves around whether or not these service should fit into already existing products (which could lead to them not being used to their full potential) or create bespoke locational products (which could maximise the response but create challenges to keep the process open to competition).

Attachments	

Project code	**NGET_UKPN_TDI.20**	**Question Number**	**21**
Question date	**20.09.2016**	**Answer date**	**22.09.2016**
Submission section question relates to	**N/A**		
Topic	**f) Relevance and timing**		
Question	**Have you considered the range of other products that the model could be extended to include in the future? How will you ensure that from the outset, the model is designed in such a way to enable these products to be easily incorporated at the appropriate juncture?**		
Notes on question			
Answer	There are a number of reasons for including active power flexibility in the package of services being offered to National Grid under these trials, but one of them relates to this question. The control system that would be developed will be able to monitor the real-time availability of active power and, on instruction from NGET or in response to local measurment, be able to dispatch the necessary DERs. Once this capability is demonstrated, there is no reason technically why it could not be applied to dispatch one of the Balancing Services such as STOR and demand turn-up. Similarly, for Response services (Frequency Response and EFR) the TDI 2.0 system could be used to select optimal DER providers and put them in a responsive mode. Where a service needs a DER to be dispatched (rather than being primed for response) in short timescales, such as Fast Reserve, the latency of the overall system may become a limiting factor. This will be considered as part of the trial. From a commercial and regulatory standpoint, all the necessary building blocks will be in place for the procurement of wider service from DERs. Open questions remain, however, about the hierarchy of decision-making and the flow of costs and benefits to each system stakeholder. Learnings from the trial should inform these questions.		
Attachments			

Project code	**NGET_UKPN_TDI.20**	**Question Number**	**22**
Question date	**20.09.2016**	**Answer date**	**22.09.2016**
Submission section question relates to	**N/A**		
Topic	**a) Enviro+consumer bens**		
Question	**Instead of reactive compensation units, could an alternative counterfactual be:** **The SO/TO procures an operational solution(s) directly from DERs (assuming it remains cheaper than capex solution). DNOs continue to separately procure DER flexibility services to manage their own constraints. SO/DNO expected to compete for these resources to some extent. SO will activate DER resource which inefficiently increases DNO costs. SO and DNO may end up procuring two separate responses when the joint procurement of one might have solved the problem.** **The TDI 2.0 solution would allow SO and DNO coordinated access to DERs.** **Do you agree with our characterisation of this alternative counterfactual?** **We understand that the trial has the potential to benefit both the DNO and the SO/TO, but believe that this is not currently reflected in the CBA?**		
Notes on question			

Answer	To summarise your proposed counterfactual, both NGET and UKPN would access each DER in an uncoordinated way, which may achieve constraint management at a lower cost than a capex solution. There may be instances in which an operation solution is available to National Grid that is both feasible and cheaper than a capex solution, particularly in the case of active power. However, NGET's most pressing requirement for constraint management comes from reactive power. Reactive power attenuates rapidly from the point of injection or absorption to a constraint further up the network, and the rate of attenuation is strongly determined by the configuration of the network between those two points. As such, it is not clear that NGET could feasibly procure reactive power with sufficient precision from DERs without operational modelling by the DNO. We understand that the coordination of the services can provide the potential benefits. The number of the cases per year when the coordination is happening is difficult to estimate, therefore in our conservative CBA approach we did not take into account the potential benefits related to coordination. Understanding the coordination benefits will be one of the learning outcomes of the TDI 2.0 project.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**23**
Question date	**20 September**	**Answer date**	**22 September**
Submission section question relates to	**Appendix 10 – Cost benefit Analysis**		
Topic	**Enviromental and consumer benefits**		
Question	**Please explain why you have not identified any Direct Benefits from the project.**		
Notes on question			
Answer	In the TDI 2.0 project for the cost benefit analysis we use the Spackman Approach. The base cost for the comparison was BaU with investment of reactive compensation in transmission system to increase network capacity. In all cases the network capacity is the same, as is the level of carbon emission. Two methods were analysed in comparison to BaU. 1. DVC from DER with reactive compensation in transmission network 2. DVC from DER with reactive compensation in transmission and distribution network. The results from the CBA demonstrate that that using DER provides £29m direct financial benefits to the end consumers by 2050 in the south east alone. By rolling out to 59 GSP in the GB system the direct benefit would increase to £412m.		
Attachments			

Project code	NGET_UKPN_TDI 2.0	Question Number	24
Question date	**20 September**	**Answer date**	**22 September**
Submission section question relates to			
Topic	**Enviromental and consumer benefits**		
Question	**Please provide an estimate of the potential capacity/carbon/environmental benefits. This should include those associated with any deferred/avoided reinforcement and/or faster/more efficient deployment of DERs.**		
Notes on question			
Answer	Network Capacity Released and Carbon Benefits are considered as not Applicable for the TDI 2.0 approach as the network capacity released in MW capacity terms are the same in today's model and those used in the innovative approach TDI 2.0. This means that the same scenario for the Distributed Energy Resources connection is used in the today's model as in the TDI 2.0 approach. **Network capacity released:** As it is explained in details in the Cost Benefit Analysis document in Appendix 10, the scenario for DERs connected was received from Regulatory and Strategy team from UKPN. The same scenario was used as the assumption in the TDI 2.0 approach. Therefore the TDI 2.0 approach does not release additional capacity in comparison to what could be connected in the business as usual approach however, we are releasing the capacity in more cost beneficial way than today' model approach. Based on amount of network MW capacity, our calculation showed that we would be able to connect 3720MW of DERs, taking into consideration diversity factor between 70 – 100%. **Carbon reduction benefits:** As the TDI 2.0 approach does not release any additional network capacity in comparison to business as usual approach, there is no additional carbon benefit with TDI 2.0. Sections 3 and 4 explained the carbon reduction results which are related to network capacity obtained and the numbers are associated with carbon reduction costs. That numbers are equal in business as usual and in the innovative TDI 2.0 approach. However, the innovative TDI 2.0 approach will potentially stimulate more DER connection, which potentially could bring additional carbon benefits. Therefore, as there are no additional benefits in network capacity released or carbon benefits in comparison to Business as Usual method. However, there is direct financial benefit in the TDI 2.0 (£29m in South East only and £412m when rollout in GB network) approach in comparison to today's model and potentially a faster and more efficient connection of future DERs.		

Attachments			
Project code	**NGET_UKPN_ TDI 2.0**	**Question Number**	**25**
Question date	**27 September**	**Answer date**	**29 September**
Submission section question relates to	**NA**		
Topic	**Enviromental and consumer benefits**		
Question	**Please revisit Question 23 with respect to the definition of Direct Benefits given in the NIC Governance Document.**		
Notes on question			
Answer	For the TDI 2.0, the direct benefit as defined in NIC Governance Document will not occur during the trial period. We did found that any of existing investment will provide direct benefit to TDI 2.0.		
Attachments			

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**26**
Question date	**27 September**	**Answer date**	**29 September**
Submission section question relates to	**NA**		
Topic	**European interactions**		
Question	**To what extent do you envisage that active power products procured via 2.0 now and in the future might also be used for frequency management (ie energy balancing)? How would the learnings of the TDI 2.0 project be used to inform development/implementation of project TERRE and the balancing guidelines? For instance, will there be consideration of how DNO needs can inform prequalification procedures, 'unavailable' bid markings, and a common merit order of dispatch (at least for directly activated standard products and specific products) to meet both DNO and TSO needs?**		
Notes on question			
Answer	The trial will only focus on the TDI 2.0 services, however the technical solution will have the ability to manage active power and the commercial arrangements in place could be extended to deliver reserve and response services. Key learning that can inform development of project TERRE will be on how to increase small DER participation in balancing services and the role of the DNO need to have to ensure this is viable.		
Attachments			

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**27**
Question date	**27 September**	**Answer date**	**29 September**
Submission section question relates to	**NA**		
Topic	**Robust methodology/ready to implement**		
Question	**The response explains that NGET 'will need to define rules for situations in which local constraints and TDI 2.0 service requests coincide'. What approach is envisaged where a conflict emerges between the needs of the DNO and the SO? How is it envisaged that this would be managed?**		
Notes on question			
Answer	The technical heart of the TDI 2.0 project is to automatically take in the reactive capabilities declared by the individual DER at their connection sites and then to calculate, considering Distribution Network Constraints, the capability that can effectively be offered to National Grid at the Grid Supply Point without causing UKPN operational issues. National Grid will then include this "Virtual Power Plant" reactive capability at the Grid Supply point in the real time optimisation of voltage control and reactive power reserves on the transmission system and advise UKPN on the desired operating condition at the Grid Supply point. Using the TDI 2.0 platform, UKPN will dispatch the individual DER to achieve this state at the Grid Supply point. As the TDI system is considering the Distribution System operating constraints in the calculation of the reactive capability that can be offered to National Grid at the Grid Supply Point, the system will avoid any conflict in the operation of the Distribution Network and the reactive power made available to National Grid. This will mean there will be variations in the reactive power capability being made available to National Grid at the Grid Supply Points. These variations will be managed in the same way as National Grid currently manages voltage and reactive power reserves, re-optimising as system conditions change.		
Attachments			

Project code	**NGET UKPN TDI 2.0**	**Question Number**	**28**
Question date	**27 September**	**Answer date**	**29 September**
Submission section question relates to	**NA**		
Topic	**Enviromental and consumer benefits**		
Question	**You note in your response to Q22 that 'it is not clear that NGET could feasibly procure reactive power with sufficient precision from DERs without operational modelling by the DNO'. However, in the response to Q18 you state that 'National Grid has a number of established contract frameworks with providers within the distribution network... These services include modulation of real power for frequency control and reactive power for voltage control'. It would be helpful to understand how distributed reactive power services are used currently and how the operational modelling problem is managed.** **Is there any data NGET can provide us with (even if incomplete) which gives a sense of the costs associated with the current lack of coordination, and the benefits which the TDI 2.0 project could deliver in providing this co-ordination?**		
Notes on question			
Answer	In our previous response regarding contractual frameworks and services from embedded service providers we included that National Grid purchased reactive response from embedded generation. These are large power stations connected in the Distribution Network but required to comply with the Grid Code and obliged to have Mandatory Service Agreements with National Grid under the CUSC framework. There are two such plants in the UKPN network, Shoreham CCGT (400MW) near Bolney and Thanet Offshore Wind Farm (315MW) near Canterbury North. In practice the use of reactive power by National Grid from these large power stations is restricted by the local Distribution Network capabilities and generally a single connection design restriction is given to National Grid on use of reactive capability. The automatic calculation of effectively useable reactive capability translated to the Grid Supply Point considering regular updates to distribution network topology should also increase the effectiveness of these large generating stations. However, the main thrust of TDI 2.0 is focused on gaining the use of		

	reactive response from DER or small generators which are currently invisible to National Grid. Currently service purchaced from DER by National Grid are for frequency response and power reserves so generally require the increase in power production when the service is called for. Automatic Network management schemes are employed in the Distribution Network to control power flows by restricting DER power output. So services to National Grid requiring sudden increased power output could be in conflict with management of Distribution Network power flows. Currently we are using very little reactive power from generation in the distribution network, because of the difficulty in ensuring that reactive dispatch does not cause issues for distribution network. Based on assessment from MPE during the project we might estimate that 5-10 % of the saving might be attributed to the coordination element.
Attachments	

Project code	**NGET_UKPN_TDI 2.0**	**Question Number**	**29**
Question date	**06 October**	**Answer date**	**11 October**
Submission section question relates to	**NA**		
Topic	**Enviromental and consumer benefits**		
Question	**You note in your response to Q28 that 'Based on assessment from MPE during the project we might estimate that 5-10 % of the saving might be attributed to the coordination element.' It would be helpful if you could clarify what is meant by 'the saving' - whether you were referring to a specific element of the saving (eg, the Steady State Voltage Opex saving), or the total project saving.** **Is there any analysis, such as the MPE analysis mentioned in your response to Q28, that you could provide us with, which helps to clarify the 5-10% figure?**		
Notes on question			
Answer	In Q28 you asked us to give a sense of the costs associated with the current lack of co-ordination with current embedded reactive service providers, Thanet and Shoreham. As stated, our answer was an estimate of 5-10% of operational costs to convey the sense that this was a potential benefit from the TDI2.0. There is no direct data from the M.P.E. analysis to support this estimate beyond the relative capacity of these providers in relation to the pool of distributed Energy Resources. The SO dispatch of the steady state voltage control capabilities of these two sites is tightly limited by simple generic operating rules which protect the Distribution Network under worst case operating conditions as there is no efficient mechanism for calculating and advising the SO of the day to day limitation.		
Attachments			