8. We will make it easier for you to connect to and use the network

What you can find in this chapter

What this stakeholder priority is about

We have many customers who want to connect to and use our electricity transmission network. We provide them with network connections, services related to the connection, and ongoing services once they're connected. We aim to achieve this by becoming a more customer-centric business. This stakeholder priority is about making it easier for customers to connect to and use the network.

What you have told us so far

You want our business to:

- provide a simple, flexible, affordable and co-ordinated approach to connections; to reduce lead times and share developer risk
- provide more support upfront before you make an investment decision
- make our charges more stable and improve the transparency of them
- improve information about planned outages on the network and minimise changes to them.

What we will deliver

We will ensure we are ready to **deliver whatever our customers require** of us. We have built the detail of our baseline plans for this priority on the Common Energy Scenario.

We will invest to **connect new customers enabling 15.3GW of connections**. 69% is from renewable sources, technologies that optimise the use of renewable energy and from interconnectors that allow renewable energy to be imported from other countries.

We will be **installing [redacted] super grid transformers (SGTs)** to support our demand customers.
We will manage the uncertainty over how many, and what type, of connections we will need to make in the 2020s through improved uncertainty mechanisms. These make sure consumers only pay for the work we must carry out as the energy system develops in the future.

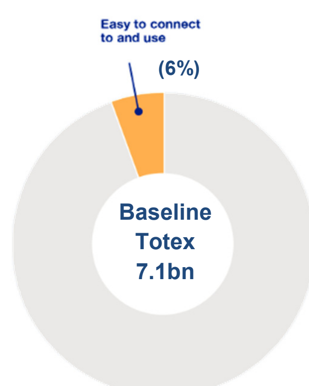
We will **deliver better customer service**, enabling more choice and a more tailored service.

We will develop **output delivery incentives** for service areas that **our customers value**, such as connections and outages and have included them in our business plan.

We are working with others to make improvements to the regulatory framework to make our charges more stable.

The cost of delivering these baseline proposals is £417m. This represents 6% of the overall business plan as reflected in figure 8.1. The baseline is approximately £105m lower through taking a whole system approach to addressing fault level issues at the distribution interface.

Figure 8.1- Proportion of expenditure



1. What this stakeholder priority is about

With the decarbonisation, decentralisation and digitisation of the energy industry, the way networks operate and how electricity is consumed will change.

In order to meet the net-zero carbon emission target, we will need to connect more renewable generation and more demand. This priority will support and enable this journey by focusing on the following areas:

1 Expenditure that is required to facilitate:

- the connection of new electricity generators and storage operators to the network
- the works associated on the transmission network for Distribution Network Operators (DNO) and other customers that consume power, such as rail companies, data centres etc

2 Expenditure and activities that will improve the customer experience for all of our customers connecting to or using the network. This means investing and improving our systems, our people capability and the processes we follow.

Consumer Value Proposition (CVP)

The CVP looks at the value we are providing above Ofgem's minimum requirements that we can robustly monetise. This chapter contains the following CVP items:
CVP3 - Whole system approach to low-voltage substation re-builds (value of £9.48m)

For more detail, please see chapter 5.4 and the CVP annexes ET.07 to ET.07C.

Energy scenarios

The customer driven investments set out in this chapter are dependent on the changing needs of our customers. We have built our business plan using an England and Wales energy scenario built from our own market intelligence and the stakeholder engagement we have undertaken. Our scenario is consistent with the minimum values in the Energy Networks Association (ENA)'s Common Energy Scenario, as required by Ofgem. As the Common Energy Scenario (CES) is not consistent with delivering Net-Zero by 2050, our proposed uncertainty mechanisms are a critical enabler of the transition to legislated targets at least cost to consumers, alongside our baseline totex plan. These mechanisms are set out and evidenced in section 7 of this chapter with more detail in annex NGET_ET.12 Uncertainty mechanisms.

2. Track record and implications for T2

2.1 Costs and outputs in the T1 period

In terms of what we delivered in the T1 period and the targets associated with this, Electricity System Operator (ESO) and Electricity Transmission (ET) collectively met the offer delivery target of within 90 days, 100% of the time up to the point of legal separation on 1 April 2019.

8.2 Customer connection offers in the T1 period

RIIO target	13/14	14/15	15/16	16/17	17/18	18/19
100%	●	●	●	●	●	●

To date, we have also delivered our outputs required for connecting generation and demand customers in the T1 period. Initial forecasts are shown alongside current forecasts for the 8-year period in table 8.3, below.

Table 8.3 Costs and outputs in the T1 period*

Category	Initial T1 forecast		Current T1 forecast	
	Outputs	Cost	Outputs	Cost
Generation	26.3 GW	£1,388m	12.6 GW	£670m
Demand	[redacted] SGTs	£355m	[redacted] SGTs	£265m
*allowances automatically adjusted by uncertainty mechanisms, as described below (2018/19 prices)				

Generation – Our 8-year forecast is that we will connect 12.6GW of transmission-connected generation, of which 47% is clean generation. The overall reduction in baseline outputs has reduced allowances by £972m from £1.45bn. We are forecasting to spend £670m with forecast allowances of £416m, an overspend of £254m. For further information please refer to section 2 in annex NGET_A8.02 Generation IDP.

Demand – The amount of SGTs required has reduced from [redacted] units in final proposals to [redacted]. The overall reduction in baseline outputs has reduced allowances by £188m from £355m. We are now forecasting to spend £265m against allowances of £167m. For further information please refer to section 2 of NGET_A8.03 Demand IDP.

Volume changes due to changing customer needs

Across the eight years of the T1 period, the major influence on the difference between expenditure and allowances has been the changing requirements of our customers in terms of the contracted generation and demand connections. The changes that we have faced have been in both volume and timing of customers connecting to the system.

Automatic adjustment of allowances

We expected that there would be a change in customer requirements and had uncertainty mechanisms that adjusted our allowances. These worked well overall and made sure consumers only paid for the work our customers required. A mechanism was put in place providing a unit cost allowance for each additional MW or SGT installed. Considering the level of change experienced, the suite of mechanisms has worked reasonably well to adjust our allowances to reflect changing customer requirements whilst maintaining a strong incentive on us to drive efficiencies.

T1 benefits are embedded in our T2 plans

We have delivered all customer connections to date at lower cost. For generation, we have estimated at least £264m efficiency improvements against project costs that we might have expected to incur given prevailing investment and procurement approaches, as well as the industry codes, at the start of the T1 period. We reduced costs by identifying innovative solutions, applying lean asset design principles, reusing assets and finding improved commercial arrangements. For demand, we have estimated at least £141m has been delivered through commercial solutions for active network management and technical solutions like optimised scope, and the introduction of lean design techniques. These efficiencies have all been fully embedded into the T2 plan.

Innovation in the T1 period

We have been using tertiary windings on transformers for reactive power supporting equipment. Through innovating, we realised we could increase competition through an alternative use of tertiary winding of the transformer. We were able to engineer the use of tertiary winding to connect our smaller generation customers. This connection on average is **£3.2m** cheaper. This has reduced cost for consumers and facilitated quicker connections.

We also innovated by offering our land around substations which is not currently operational. As our land is near the substation, it allows developers to reduce project cost and lower risk, through shorter cable lengths, and provides cheaper connections that benefit both our customers and the end consumer.

Whole systems approach

Creating consumer benefit through a whole system approach is something we are doing in the T1 period – we worked with DNOs to install 9 Automatic Network Management (ANM) schemes for distributed generator connections as an alternative to spend on SGTs. In total, we estimate that these schemes will reduce costs by between **£90m-£108m** by avoiding the need for additional SGTs within the T1 period and saving consumers money. See annex NGET_A7-8.03 Whole Systems which details our approach.

Transmission reinforcements to resolve distribution network issues – across the T1 period, there have been instances where the DNO network required significant upgrades to accommodate increasing power flows. By working collaboratively, we and the DNOs were able to assess if a transmission investment could alleviate the issue at a lower cost to consumers. In some cases, this analysis showed that the transmission reinforcement provided better value for the consumer.

Price control effects

Costs and allowances can also vary due to mechanisms in the price control, such as those required to deliver outputs beyond the second year of the T2 period.

Our costs differ from allowances set at the start of the T1 period due to changing customer needs, cost efficiencies, innovating and price control effects. This is illustrated in figures 8.4 and 8.5, below. Given considerable changes in the projects delivered versus those that were expected to be delivered, it is not possible to define a baseline against which to specifically measure efficiency

Figure 8.4 Costs and allowances for generation investment

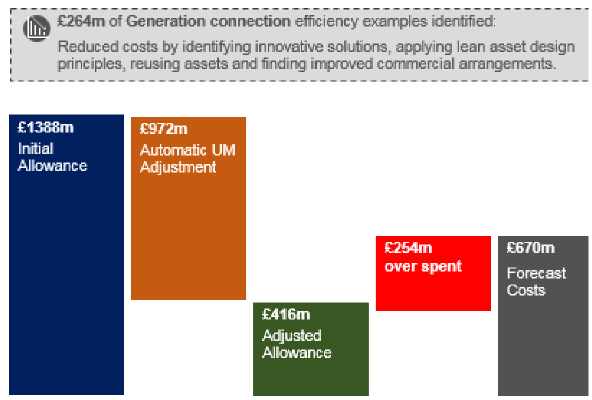
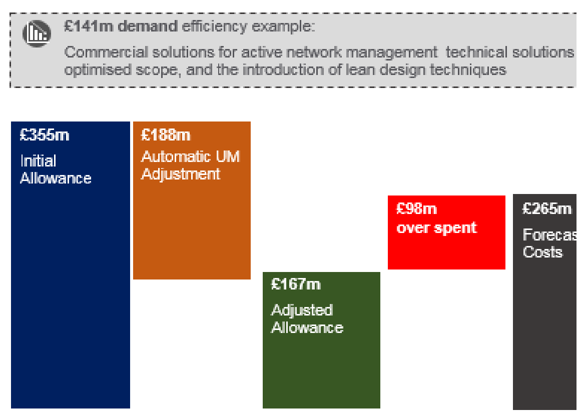


Figure 8.5 Costs and allowances for *demand* investment



*Excludes connection costs

2.2 Improving our customer experience

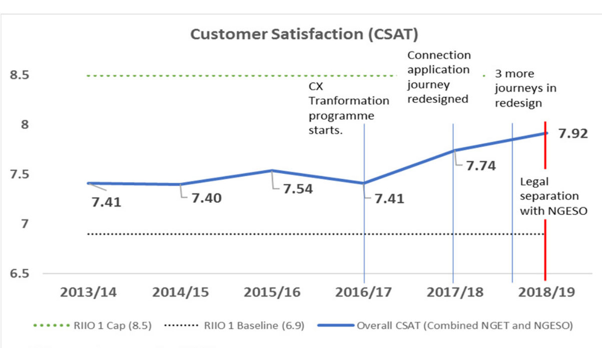
Our customer satisfaction tracker informed us of how our customers, both those in the connection pipeline and those already connected, felt about the quality of the Customer Experience (CX) we provided. Year-on-year, it has been tracking this in 10 core service areas across the ESO and ET operations; 3 shared by or wholly operated by ET and the remaining 7 wholly within the ESO.

Although we consistently delivered connection offers within the 90 day obligation, we observed that customer satisfaction had in fact plateaued – we were delivering on time, but the quality of experience was not meeting the customers' needs. This led to the launch of our customer experience transformation programme in 2017 and the redesign of our connection journey and other core customer journeys across ESO and ET. The insight we had through the voice of the customer (VOC), an in-depth process of capturing customers' expectations, preference and aversions, led us to produce our five core principles (to **care**, be **agile**, be **transparent**, earn **trust**, deliver **value**) which were fundamental to improving the experience felt.

We recognised that the changes that we needed to adopt were not merely process adjustments but primary behaviour changes running right across the business from leadership to frontline – our culture. Embedding the changes that customers were needing to experience started and ended with our people; from how we communicate and take ownership to how we listen and collaborate with one another. These were all essential steps to providing the service our customers have told us they need. We now fully understand that employee engagement, alignment with a common purpose, clarity of direction, prioritisation and enablement through systems, tools and empowerment pave the way to the local sustainable changes that need to be made at each and every customer touchpoint. We also recognise that our moving from silo working within a decentralised model to a federated model, that enables the required CX governance for CX data management and processes, is essential to achieve our customer ambition overall.

By challenging how we operate against our five principles, our customer satisfaction (CSAT) started to increase, starting with the connections applications process and activities undertaken by the Transmission Network Control Centre (TNCC).

Figure 8.6 Customer satisfaction scores so far in the T1 period



The early deliverables of our customer experience transformation programme have laid the foundation for what we need to develop and deliver by the end of the T1 period and across the T2 period – all shaped by the voice of the customer.

- **A fully endorsed customer experience ambition** with customers and National Grid Group
- Our **customer experience set of principles and standards**, to roll out consistent best practice across our business.
- A **customer experience governance board and net promoter score programme** to drive cultural changes at all levels of our organisation.
- The early development of **a customer relationship management system** that enables us to provide a consistent and efficient customer experience and supports our goal of delivering a personalised customer experience.
- Our **customer journey mapping** work has been crucial in delivering better outcomes for customers, and implemented them. We will continue to have dialogue with our customers to ensure that the changes we implement are making a difference to their experience.
- An **improved website** that now includes information that our customers wanted e.g. network capacity map.

Connecting to the transmission network

Through the journey redesign work and our focus on improvement initiatives focusing on the application stage, we have improved our connections score from 7.5 to 8.0 between 2016 to 2019. We continue to innovate to make further step changes to this particular service experience. We are committed to continue to identify the evolving drivers of customer satisfaction and use the voice of the customer to shape what we need to do to improve their experience.

Learning for the T2 period

Taking time to reflect on learnings from the T1 period has been an integral part of shaping the T2 business plan.

The number of connections we had to provide in the last eight years was very different to what we and the industry anticipated at the beginning of the period. As our baseline plan was based on the central view of the energy scenario envelope (i.e. Gone Green), it is likely to lead to significant revenue adjustments through uncertainty mechanisms. We have engaged stakeholders and other networks to agree a common energy scenario in between the extremes, reducing this risk in the T2 period.

We have learned about the importance of uncertainty mechanisms to ensure our allowances reflect the connections our customers want us to carry out and ensure consumers only pay for what our customers want.

Investment driven by embedded generation has not been dealt with by the T1 price control framework, this has potentially impacted whole system solutions; moving into the T2 period, we are proposing an uncertainty mechanism that deals with investment that is driven by embedded generation.

We have learned that our uncertainty mechanisms could be more accurate so that the adjustment to our allowances more accurately reflects our costs. Further details on how the learnings from uncertainty mechanisms (UM) in the T1 period has shaped our latest thinking on UM development for the T2 period can be found in section 7 of this chapter or a detailed explanation can be found in annex NGET_ET.12 Uncertainty Mechanisms.

We have also learned that improving customer service is a cultural journey. We should have done more in changing the culture around customer and should have done this sooner, hence our CX strategy to drive customer centricity into the DNA of our business.

Our customers want more than a timely connection. The quality of our customer service also matters to them. Working with more new and smaller customers recently and learning about their specific needs, we have realised that different types of customer want different services. These learnings include new customers being less familiar with our processes and procedures, requiring more support, and application fees being a barrier for them. In response to this, we created web tools to facilitate feasibility assessment and will be looking into bespoke services in the T2 period.

In respect to project delivery, we need to be more agile and innovative in connecting customers quicker. We know that consenting is a factor in connection lead-time. We are looking to use our experience from these projects to deliver the required pre-application consultation and engagement more effectively, better targeting resources at key aspects, considering the timing of high resource commitment activities in the process, and being more proportionate in the information we produce. By taking this approach, we think we can reduce the time to achieve consents, reduce the duration, and improve the cost profile, of the process for the benefit of consumers.

3. What our stakeholders are telling us

Our plans must be shaped by our licence obligations – the rules that we must follow to connect customers to the network. We have engaged based on this framework and these have been described in table 8.7 below.

Table 8.7 Our obligations when connecting customers

CUSC	The Connections and Use of System Code (CUSC) is the contractual framework for connection to, and use of, the National Electricity Transmission System.
SQSS	The Security and Quality of Supply Standards (SQSS) provide a set of criteria and methodologies that transmission licensees must use when planning and operating the network. It is our licence obligation that we connect new and existing customers to the network in compliance with the SQSS. This ensures the safe and effective use of the network.
STC	The System Operator-Transmission Owner Code (STC) defines the relationship between the transmission owners and the system operator. The STC clearly sets out the roles, responsibilities, obligations and rights of each party in detail.

A summary of our engagement activities and outcomes is provided in table 8.8 below, alongside what trade-offs have been made and how stakeholders have influenced the plan. The engagement log contains detailed information on our engagement approach and outcomes. This can be found in annex NGET_A8.01 Engagement log (Connections and use of Network).

Table 8.8 Summary of our engagement

	Engagement on improving connections
Purpose and approach	The purpose of this engagement was to understand our customers' views on how we can make their connection to the network as easy as possible by using data from customer satisfaction feedback, bilateral meetings, bespoke research and interviews, our 'Future of Electricity Transmission' webinar and our 'connection journey' workshop and accessibility testing with consumers.
What stakeholders told us	Stakeholders told us that they want a simplified, flexible, affordable and coordinated approach to connections. They also want us to provide options for a wider range of services such as increased digital services or support through the consent process. Providing more information and support upfront before they make an investment decision was also really important to them. Some of the specific feedback was that some customers thought we were unable to deliver their connection because of their small size, so they connected at the distribution level instead. Customers also fed back that it can sometimes be difficult for new entrants to the sector to work with us: "There are a lot of new entrants into the market and trying to unpick how to engage and how to work with National Grid can be a real problem, unless you've got people who have years of experience in the industry. If you're coming in fresh, then it's quite complicated." Customers would like more online platforms to help speed up the connections process. (Source: Bespoke Research, further details are in NGET_A8.01 Engagement log – Connections and use of Network)
What consumers told us	Quantitative acceptability testing showed strong support for our proposed investments, 92% of respondent's agreed with the proposed investment of connecting new power generators and 71% agreed with the proposed investment and impact on bill is acceptable.
Key trade-offs and how engagement influenced our plans	A **key trade-off** was whether to include costs in our baseline to manage additional thermal capacity and fault level capacity to address the impact of embedded generation on the transmission network, where whole system alternatives could exist, or whether to exclude these costs from our baseline and develop an uncertainty mechanism that would provide funding where transmission investment is the best solution for consumers. Based on the insights gathered through this engagement, we have decided to fully embrace the potential of whole system solutions to reduce costs for consumers, thereby reducing our baseline proposals by £105m. Uncertainty on roles in the whole system planning process was highlighted by some DNOs and there were different views on the role of the TO. Some DNOs were keen to work exclusively with the ESO, whilst the ESO and other DNOs indicated a preference for full collaborative working. Most preferred the collaborative approach and, on balance, we think this is likely to lead to better consumer outcomes. As such, our proposals are based on this approach. Another **trade-off** was between increasing the number of employees dealing with the connections process versus the development of digital platforms for self-service. Through our engagement, many of our customers and potential customers wanted an increase in the self-serve online capability (i.e. customers will be able to use the functionality to design their own connection). We took the decision to invest in the IT capability supporting what customers wanted. As described in chapter 6 *Giving stakeholders and consumers a stronger voice*, Frontier carried out an assessment on our engagement and highlighted that there was limited evidence customers wanted to directly contract with the TO, we have responded by removing the commitment for this.
How we've responded to the Independent Stakeholder Group and Challenge Group	The **Independent Stakeholder Group** challenged us on how we could provide more certainty on connection dates for customers and take on more risk. Our stakeholders also want us to take ambitious action on climate change by reducing greenhouse gas emissions. In addition, the UK government has put into law the target of net-zero greenhouse gas emissions by 2050. Based on this stakeholder feedback we have developed an ODI to encourage us to deliver earlier connection dates to benefit our customers and to bring forward the reduction in greenhouse gas emissions from low-carbon generators connecting to our network. Another challenge raised by the **Independent Stakeholder Group** around how we will ensure that our approach to connecting small vs. large customers is proportionate. To ensure that we are setting ourselves up to deal with these challenges in the most effective manner, and as part of our focus on the customer connections journey in the T1 period, we have an ongoing piece of work in this area that has highlighted the potential benefits of standardisation for smaller projects. This is something we will continue to investigate and ensure we incorporate learnings into our approach in the T2 period. We are also investing in our online capability to allow some customers to customise their connections.

	Engagement on better coordination of planned outages
Purpose and approach	The purpose of this engagement was to understand our customers' views on how we can carry out vital repair work on the network with least disruption to our customers. Feedback was obtained via the following channels; customer satisfaction feedback, bilateral meetings, interviews with network companies and workshops.
What stakeholders told us	Customers have told us that we do not sufficiently communicate or explain the changes we make to outages and that we do not fully appreciate the impact our decisions can have on their business. Some emerging themes were: • in some cases, we do not sufficiently explain the reasons for our changes • in some cases, we do not sufficiently assess the impact of our planned outages which subsequently get cancelled • there are delays to works which create more changes in planned outages.
Key trade-offs and how engagement influenced our plans	Our engagement has influenced our plans as we are creating higher detail long term plans in collaboration with stakeholders and we are trying to be more transparent with our plans to get earlier feedback and understanding of the impact of our work on our stakeholders. We have put a greater focus on "systems" as part of our deliverability reviews ahead of plan submission to test that plans are credible and deliverable considering wider system limitations to ensure that customers are not impacted or we are able to manage the risk without negative consequence.
How we've responded to the Independent Stakeholder Group and Challenge Group	In defining the ODI for outage experience, the **Independent Stakeholder Group** highlighted the opportunity to work with Ofgem and incorporate this ODI into the common ODI for quality of connections. As a result of this feedback, we will work with Ofgem to establish if this would be feasible.

	Engagement on improving the stability of our charges
Purpose and approach	The purpose of this engagement was to understand our customers' views on our charges via customer satisfaction feedback, bi-laterials meetings, customer seminar, 'connection journey' workshop.
What stakeholders told us	Customers told us that year on year Transmission Network Use of System (TNUoS) volatility is a concern because this has an impact on their business. The ESO has also informed us that the polling that took place during customer seminars gave the same message. Customers would like us to be more transparent and communicate more effectively with them when there are changes to connection cost volatility during the build phase. For example, from a Customer Connection Journey meeting, we heard that we "give no pre-warning of cost increases in the project, no options to query at the time", this causes a problem as our customers are presented with a bill at the end.
Key trade-offs and how engagement influenced our plans	The ESO and stakeholder feedback has resulted in us looking to include actions that we could take to help address this concern.
How we've responded to the Independent Stakeholder Group and Challenge Group	The **Independent Stakeholder Group** wanted to see detailed proposals for the load related driver – we have included much more information on uncertainty mechanisms in the plan, including the T1 period experience and learning, and our proposal for the T2 period, and how this will help with charging volatility.

4. Our proposals for the T2 period

The table below outlines how what stakeholders are telling us links to the proposals we are making and the consumer benefits.

Table 8.9 Our proposals for the T2 period

Stakeholder Feedback	Our proposals	Output type	T2 Baseline (£m)	Consumer benefit
You want us to make it easier to connect to the network	We will invest in the network to connect 15.3GW of new generation, storage and interconnector for customers under the common energy scenario.	**LO** to connect MW of new generation **Bespoke ODI-** Accelerating low carbon connections	245.0	Help lower wholesale electricity costs and reduce carbon emissions.
	We will invest in the network to connect demand customers when they request connections by installing [redacted] super grid transformers (SGTs) under the common energy scenario.	**LO** to install SGTs	141.7	To connect large consumers quickly and efficiently.
	We will invest in our systems, people and products to delivery our CX strategy.	**Common ODI** – Quality of connections survey	29.9	Improving our customers' experience, and meeting their needs, will benefit the consumer.
You want us to make it easier to use the network	We will make step changes to improve the system access experience for our customers so that they have more warning of network outages and changes to them.	**Bespoke ODI-** Outage management	N/A	Improving our customers' experience and meeting their needs, will benefit the consumer.
You want our charges to be stable and predictable	We will contribute to improving the stability and predictability of our charges.	**Commitment** to work to improve the regulatory framework to improve the stability and predictability of our charges.	N/A	

5. The justification of our proposals

5.1 Our proposal to make it easier to connect you to the network

Our proposals will be delivered by the investments and commitments outlined in this section. These are driven by our legal/licence obligations, ensuring that the options considered meet standards and the needs of our current and future customers.

The Common Energy Scenario did not provide a project-specific view of connections. Therefore, to develop a detailed business plan, we have utilised project-level intelligence - 'project health status'- to assess the projects within each technology type that are most likely to proceed. Details of this assessment can be found in annex NGET_A8.02 Generation IDP.

Projects that have achieved planning consents, are financially committed, and have obtained a Contract

for Difference or Capacity Market agreement are more likely to proceed than those that have yet to secure these. Those projects which are most likely to proceed, have been included in the business plan. Despite this, we do not have perfect foresight of connections and the actual mix of generation is likely to be different from that assumed.

The progression of connection investments is governed by our Network Development Process, which ensures that the most cost-effective solution to customer requirements is delivered. Using our own analysis and dependent on the location, size and type of plant, we have assessed all investments proposed in this chapter to be the most economic and efficient way to deliver the outputs. These are evidenced in the investment decision packs, which include an engineering justification paper and cost benefit analysis (CBA). Our costs to develop this part of the business plan are **based on externally verified benchmarks**, as detailed in chapter 14 *'Our total costs and how we provide value for money'*.

i) Invest in the network to connect generation, storage and interconnector customers

Key driver – Our business plan proposes a baseline allowance of £245m to connect 15.3GW of generation, storage, and interconnector projects during the T2 period. 69% is from renewable sources and technologies that optimise the use of renewable energy (e.g. wind and storage); and from interconnectors that allow renewable energy to be imported from other countries. This will support the UK achieving its net-zero emission goal.

The need for new connections, and the associated network investment, arises from customer applications to connect to the transmission system via NGESO. Upon receipt of an application, we assess the customer's request and identify the most economic and efficient solution to facilitate their connection.

We have robust processes in place to ensure that appropriate investment development is undertaken at the right time; that scope and cost estimates are robust; and that lessons learnt are captured and incorporated in future projects. It is inappropriate to make unit cost comparisons (£/MW) between projects expected to be delivered in the T1 period and the proposed baseline for the T2 period. This is because the proposed mix of projects anticipated to connect in the T2 period is very different (and consistent with the Common Energy Scenario).

Options – Using our engineering expertise, we develop a range of options and then assess these using a cost-benefit analysis to determine the most economic and efficient option. For example, the options considered to connect a project <50MW are:

Option Selection Summary
Options considered (Selected option in bold)
Option 1: Do nothing would not be consistent with our licence obligation to make an offer to connect.
Option 2: Innovative connection using tertiary windings
Option 3: Conventional connection by installing a new SGT
Option 4: DNO provided connection

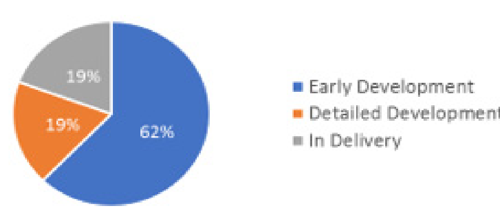
We have justified our proposed baseline allowance, through 5 detailed case studies of the investment decisions we have made and 20 individual cost-benefit assessments, these are described in annex NGET_A8.02 Generation IDP.

Well designed and calibrated uncertainty mechanisms will ensure allowances adjust appropriately, should the mix of customer projects change from that assumed, and provide an incentive to minimise investment costs.

Whole system alternative – In the case of connection for offshore wind farms and interconnectors, there are two stages of option selection. First, a process to determine the optimum onshore connection point, then a process to optimise the design of the agreed onshore connection. The first phase of this delivers a Connection and Infrastructure Options Note (CION)[1] and involves extensive close working between the customer, other transmission owners, and the ESO. The purpose of the CION is to ensure that the best whole system solution is selected and progressed.

Cost justification – Figure 8.10 summarises the maturity of the development activities of investments in our business plan. It shows 62% of investment during the T2 period is associated with projects in the early stages of development that have estimates based on the Cost Book, derived from internal historical benchmarks. The unit cost key assets in the Cost Book have been recently benchmarked by external consultants and provided independent assurance on our cost estimate process; further details of the study and methodology can be found in chapter 14 *Our total costs and how we provide value for money*. 19% of investments have had detailed design work completed and a bottom-up cost estimate made but are not yet in delivery; and 19% are already in delivery.

Figure 8.10 – % of total T2 spend by development stage



[1] https://www.nationalgrideso.com/document/45791/download

Table 8.11 Baseline: Proposed baseline expenditure for generation, storage and interconnector connections for the T2 period

Description	T2 infrastructure costs (£m)	T2 sole user connection costs (£m) *	T2 Output MW
Works for six combined-cycle gas turbine **CCGT** developments in the T2 period.	39.3	0.0	1827
Works for **off-shore** wind projects in the T2 period.	87.6	0.0	5460
We expect five **interconnectors** to drive investment costs in the T2 period.	40.5	0.0	4700
We have included three further generation developments in the plan: two open-cycle **gas turbines** (OCGTs); and a **biomass plant** in North Wales.	13.2	0.0	1109
Works associated with 13 **battery connections**.	9.2	27.4	499
Works for one **nuclear** power station, Hinkley C, in the T2 period. These works include construction of a new connection substation at Shurton.	26.1	1.8	1670
Total	**215.9**	**29.2**	**15265**

*costs relate to generation assets installed solely for and only capable of use by an individual user. These costs are recovered through connection charges which are treated as an excluded service within the regulatory framework

In our business plan, the wind projects connecting to the network during the T2 period are all offshore. This aligns with evidence of reducing cost for this technology, the UK's Third Contracts for Difference (CfD) auction has cleared at the record low price of £39.650/MWh for Delivery Year 2023/24 and £41.611/MWh in 2024/25 and existing government policy that is more supportive of offshore wind than large scale onshore wind within England and Wales.

Further to this, the Committee on Climate Change recommended target for the UK to become net-zero of carbon emissions by 2050 suggests potential further growth in this area (up to 75GW by 2050). Offshore wind tends to be located at the extremity of the network, often away from where traditional generation has been located, meaning that notable investment is required to facilitate these connections. The recent CfD results open up the possibility for offshore wind to play a greater role in delivering net zero by 2050.

We understand that there may be dependencies such as changes to government policy in nuclear or contract for difference, the levelised cost of energy and the anticipatory investment approach taken to combine network solution may impact our forecast. Any changes that occur will be dealt with through the uncertainty mechanism.

ii) Invest in the network to connect demand customers

Key driver – our business plan proposes a baseline allowance of £141.7m to deliver [redacted] new SGTs (including 2 new GSPs) to connect new demand customers and to provide additional capacity at existing DNO connection sites during the T2 period. Drivers of these investments are our demand customers, that fall into two categories: direct connections (e.g. large, individual industrial, commercial connections or transport) and distribution networks.

Options – we identified a full set of options that satisfy the driver, including working with the DNOs to investigate non-build options and to select a preferred option by identifying with more certainty the scope, programme, costs and issues associated each of the potential options. This stage identifies a variety of different ways the driver could be met, including: no-build and less-build solutions (if they are available); use of innovative or emerging technologies (e.g. use of new conductor types); choices such as on-line versus off-line build and air-insulated versus gas-insulated solutions; the application of any lessons learnt from similar previous projects; and the current ratings different assets and technologies provide. For example, the options considered for demand driven new GSP are:

Option Selection Summary
Options considered (Selected option in bold)
Option 1: Do nothing would not be consistent with our licence obligation to make an offer to connect.
Option 2: DNO cable to existing site
Option 3: NGET construct a new Grid Supply Point

We have justified our proposed baseline allowance, through four detailed case studies of the investment decisions we have made and ten individual cost benefit assessments and a detailed description of the business as usual, and the T2 period specific, collaborative working with distribution networks, these are described in annex NGET_A8.03 Demand IDP.

We will continue to work with all stakeholders to develop and assess the whole system alternatives to new investment in this area during the T2 period. We will put in place appropriate uncertainty mechanisms to ensure we can take forward SGT investments should they be required when alternatives are not available.

Cost justification – Figure 8.12 summarises the maturity of the development activities for the investments in our business plan and shows 86% of investment during the T2 period is associated with projects in the early stages of development that have estimates based on the Cost Book that have been derived from internal historical benchmarks. For further details on the Cost Book see chapter 14 *Our total costs and how we provide value for money*; 12% of investments have had detailed design work completed and a bottom-up cost estimate made but are not yet in delivery; and 2% are already in delivery.

Figure 8.12 – % of total T2 spend by development stage

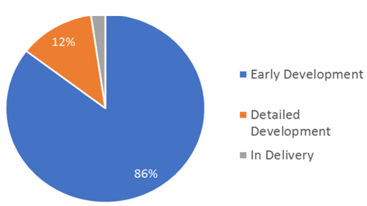


Table 8.13 Baseline: Proposed baseline expenditure for demand connections in the T2 period

Investment type	T2 infrastructure costs (£m)	T2 sole user connection costs (£m) *	Output – No. of SGT
DNO demand	88.1	51.7	[redacted]
Connecting non-DNO customers	1.0	0.9**	[redacted]
Total	**89.1**	**52.6**	[redacted]

*costs relate to demand assets installed solely for and only capable of use by an individual user. These costs are recovered through connection charges which are treated as an excluded service within the regulatory framework.
** We anticipate £1.3m of capital contribution that is paid directly by customers which has been netted off the connection costs.

iii) Driving efficiency and better outcomes through better collaboration, whole system solutions, competition and innovation in the T2 period

Proposal for a combined Network Access Policy (NAP) framework through better collaboration

The Network Access Policy will supplement the STC procedures already in place for outage planning and data sharing. It is valuable to have a policy in place to promote flexibility in both the TO and ESO with the joint focus of delivering greater overall consumer value.

We have been working with the other TOs, the ESO and customers in creating a single NAP that will promote all parties to retain focus on consumer value via the NAP forum, we propose the following:

- Performance of the Network Access Policy to be governed by a joint forum across TOs, NGESO and Ofgem (annual circulation of Chair between TOs).
- Same forum to be used for sharing of best practice and lessons learned.
- The Network Access Policy should be reviewed at least every 2 years based on lessons learned and improvements.
- Agree the content of the roles and responsibilities of a joint NAP with the other TOs and ESO before the start of T2 period.
- Creating metrics that have been advocated by our customers to ensure transparency and our impact on end consumers.
- A transformational proposal to complement the Network Access Policy which can be found in annex NGET_A7-8.03 whole system (SO-TO Optimisation mechanism).

Annex NGET_A8.04 Network Access Policy (NAP) provides further details on how we will approach delivering greater value for end consumers that go beyond our current licence obligation. This annex includes a set of metrics which we have created in collaboration with the ESO and the other TOs to feed in our customers' needs. In the foreword of this annex we have included details of the customer and stakeholder engagement we've completed in the T1 period to enhance the Network Access Policy, how we are going to continue to develop and enhance the proposed Network Access Policy through further stakeholder engagement and the development timeline.

Greater collaboration and co-ordination is driving better whole system outcomes

The growing trend for decentralised generation can present fault level challenges at Grid Supply Points (GSPs) where we retain ownership of lower voltage assets (e.g. 132kV) and this is another key driver of our investment plan.

Fault levels exceeding the rating of substation assets present a physical safety risk as well as a risk to security of supply. The default investment solution to resolve this would be to replace the equipment that has reached its maximum capability with higher rated equipment. In some cases, this continues to be the most effective, and the only potential solution. However, we have increasingly been looking to find a better way by working with DNOs, evident in the A7-8_Engagement Log (Whole system – DNO&ESO) and the ESO to determine if any non-build options can resolve fault level issues. These could include, for example, changes to running arrangements in either the transmission or distribution system.

Our analysis identified a potential requirement to invest £105m through the T2 period on low voltage substation re-builds due to higher fault levels associated with distributed generation. This requirement was included in the first draft of our business plan, which we discussed with DNOs. Through our collaboration and coordination with the DNOs, we have removed these costs from our baseline proposals and will develop a new uncertainty mechanism to cover substation re-build costs we might incur if a transmission investment is later confirmed to

be the best solution for consumers Further detail is available in annex NGET_ET.12 Uncertainty mechanisms.

Removing these investments from our baseline allows us to work with relevant DNOs and the ESO, as more information becomes available, to determine what is needed and who is best to deliver to the overall benefit of consumers. An uncertainty mechanism facilitates this flexibility.

Whilst alternative running arrangements can be effective, they normally represent a move towards a more complex network operating condition and can restrict capacity for further connections and increase future network access costs. If more distributed generation customers connect, the fault levels limits could be exceeded, and investment may be triggered.

Projects meeting OFGEM's competition criteria

There are no projects that meet the >£100m threshold for late competition. Based on the criteria for early competition (high value >£50m, are the network requirements new and separable, how time critical are the requirements, the certainty of need and opportunity for innovation), we have undertaken an assessment to determine whether any connection projects would be subject to competition, and have identified two projects that would initially meet the >£50m criteria; King's Lynn B and East Anglia (1N-2). However, upon further review we have determined that neither of these projects would be suitable for early competition as outlined in table 8.14 below, further information can be found on the competition criteria in chapter 7 *We will enable the ongoing transition to the energy system of the future.*

Table 8.14 – Competition assessment against Ofgem's competition criteria

Project Name	Project Cost (£m)	Finish Date	New and Sep.	Time criticality	Certainty of need	Scope to innovate	Comments — **Suitability for competition against our criteria**: Limited suitability ○ ◔ ◑ ◕ ● High suitability
Kings Lynn	[redacted]	2023	○	○	◑	◔	The project development for King's Lynn B, including gaining a Development Consent Order (DCO) for the new overhead line is complete. There is therefore little scope for innovation or in delivering an alternative solution which may lead to cost savings. Furthermore, King's Lynn is currently contracted for a 2023 connection (dependant on gaining market capacity) and in order to achieve this date, National Grid would be seeking to approach the market for substation and overhead line proposals by February 2020. Running a competition to first appoint a TO would impact on these dates.
East Anglia (1N-2)	[redacted]	2027	○	◑	◕	◔	The East Anglia (1N-2) project is required to accommodate several new connectees, including offshore wind and interconnectors, and the design and layout is linked to the capacity and timing of each of the connections. Should any projects change their required capacity or terminate, the design would feasibly need to change to account for this. Due to the design complexities and potential variability, and the number of customers and stakeholders involved, we do not believe that this project would be suitable for competition.

Innovation and efficiency

We have embedded innovation developed in the T1 period into our T2 plans and will continue to connect smaller customers using the tertiary connection approach in the T2 period, whilst innovating to meet the needs of our current and future customers, this will on average will **save £3.2m per connection** compared to the previous transmission solution, passing on **£42m of cost saving** to consumers in our T2 plan for this priority. In chapter 14 *Our total costs and how we provide value for money* we outline how over the last 6 years our current cost base has been market tested via competitive tender, and benchmarked internally and externally. We are also making stretching commitments to future efficiencies by moving our benchmarked capex unit costs to be at or below the TNEI industry mean equating to an **£14.9m reduction** in this stakeholder priority. We have also applied a **£3.4m productivity**

commitment to improve the productivity of our people by 1.1% year on year.

iv) Delivering the right systems and products to deliver the CX strategy

Our customer experience ambition

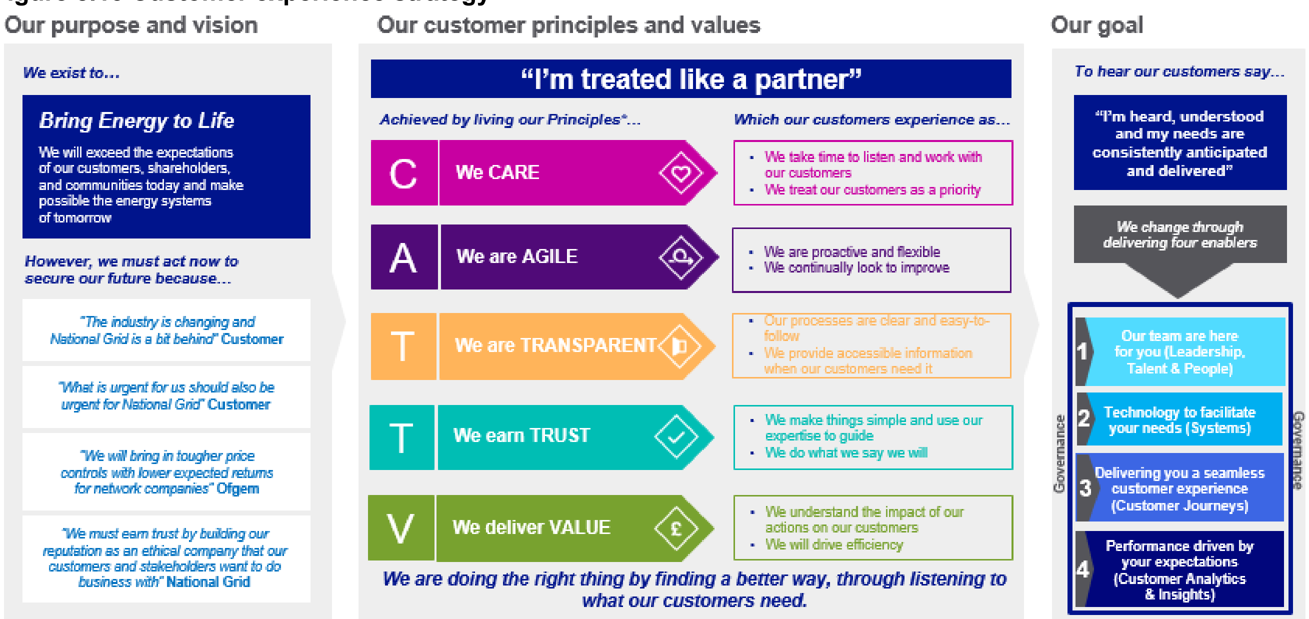
Our customers have told us that to achieve our vision of exceeding their expectations, we must listen, understand and consistently anticipate and deliver against their needs. When we do this well they will feel as though they are 'treated like a partner' – this is our UK customer ambition and forms the basis of our UK Customer Strategy to become a customer centric organisation.

Our principle: The how

The behaviour and experience our customers see defining this partnership are outlined within our principles: that we **care**, we are **agile**, we are **transparent**, we earn **trust** and deliver **value**. These customer principles were derived by exploring the drivers behind low satisfaction and net promoter scores. This customer commentary and insight show five key pain points from the customer's perspective (a lack of trust, transparency, listening, agility and understanding the impact our actions had on their business). Our customer principles directly address their pain points and form the bedrock by which we create and test our customer experience.

The Customer Experience Strategy, including our ambition, our principles, a multiyear roadmap that extends into the T2 period and an agile delivery approach, provides a clear and measurable way to ensure we focus on those activities that deliver the most value to our customers. By living by our customer principles and working in partnerships, we want to ultimately hear our customers say… "I'm heard, understood and my needs are consistently anticipated and delivered". Our CX Strategy is summarised in figure 8.15.

Figure 8.15 Customer experience strategy



IT investment

In order to deliver an increased workload in an efficient way, we need to invest in our systems, not just our people.

Our systems need to enable a tailored approach for different customers, and our IT investments detailed in the table below will help us facilitate this. We want to give customers the choice to either communicate with us using the self-service portal or have the ability to speak to a dedicated account management team. We will be flexible in ensuring that the right number of skilled resources are available dependent on the needs of the customer to ensure effective ongoing dialogue.

The Customer Relation Management (CRM) system will allow us to manage complex, multi-touch point relationships with a vast array of customers. The need, optioneering and justification of the enhancement of the CRM system and customer portal can be found in annex NGET_A14.12 IT System Heath Replacement and annex NGET_A14.07 ET IT Investment. We summarise this in the table 8.16 below.

Our IT costs have been benchmarked by Gartner Inc, who are a global research and advisory firm providing insights, advice, and tools for businesses. This report demonstrates our investments are in line with the expected range.

Table 8.16 Baseline: Proposed IT investment in the T2 period

Investment area	Description	T2 costs (£m)
CRM system for connecting customers:	In the T2 period, our CRM system will **underpin how we manage our entire customer connection process**. We will need to invest to include more parts of the journey within the CRM system, we will use the **customer insights** and **data** to make sure we can offer a more tailored, bespoke and flexible end-to-end service to different types of our customers. Our research and recent feedback has found the CRM system to be the most efficient and effective way to manage customer data and processes. The CRM system will also underpin our website and proposed customer portal investments.	5.0
CRM system for non-connection customers	There are areas of our business that interact with customers outside of the connection process, such as asset protection, the transmission network control centre (TNCC), outages and land management. Each type of customer expects a different service and experience from us. This investment is to bring these interactions into the CRM system so that we can provide a more complete customer experience, this is as a result of direct feedback from our customers.	2.5
Customer Portal - Self-service website for connecting customers	This investment will improve our customer experience with a self-service website. The portal will provide customers with a digital channel to apply/manage and interact with National Grid – streamlining interactions with National Grid, allowing customers to self-serve for elements of the connections process and customers will be able to use the functionality to design their own connection. This is in direct response to customers identifying multiple frictions with the existing connections process e.g. customers find the process of managing connections too manual and applying for a connection is inefficient and hard to understand.	2.4

v) Delivering connections quicker in the T2 period and tailoring to deliver the needs of our customers

To ensure that we provide different approaches to different customer segments, we have already restructured the organisation to achieve a multi-**disciplinary sector-based** connections team, so our colleagues can expertly support different types of customers with different needs.

For our smaller and new connection customers in the T2 period, we will **expertly support our customers** by providing additional services to help them connect quicker, these services will be:

- creating a pre-application support framework so that we can provide early guidance for potential customers, ensuring we have the right balance of resources/specialists that supports the need of the customer
- working closely with our customers to identify suitable locations for their projects where capacity is available, such that their connection can be accommodated
- providing customers with choices and options for the design, timescales and costs of their projects by collaborating with the DNOs
- use our expertise and learning from the T1 period to make improvements to the lead time to achieve consent.

We recognise that different approaches are required to deal with these different types of customers. To ensure that we are setting ourselves up to deliver for these customers in the most effective manner, and as part of our focus on the customer connections journey in the T1 period, we have an ongoing piece of work in this area that has highlighted the potential benefits of standardisation for smaller projects. This is something we will continue to investigate and we will ensure we incorporate any learnings into our approach in the T2 period. The ability to connect smaller low carbon generators will help the nation as we head towards a net-zero carbon emissions target.

We will also deliver a seamless customer experience by different customer type by using customer insights and analytics via the CRM system and our continuation of work through the customer journey to evolve and adapt our products and services to meet the needs of different types of customers.

vi) Our commitment and targets for the T2 period

The following ODIs have been developed to improve on aspects that are important to our customers, different connection customers want different things from us: lower connection costs, quicker connection dates or connection dates closer to their preferences in response to this we have created. These ODIs have been tested and shaped with stakeholders' feedback, further details on how these ODIs will work can be found in annex NGET_ET.06 Output Delivery Incentives.

Table 8.17 Output Delivery Incentives

LO/ODI commitment	Descriptor	T2 target
Timely connection offers	Ensure connection offers are made to the customer within the agreed timescales set out in the industry codes.	100%
Quality of connections survey	Common ODI to measure 'moments that matter' via a survey through the customer connection journey and 'post energisation' journey.	Target will be agreed once the pilot survey is completed.
Outage management	To improve customers' experience of outages saving them time and cost. This would allow our customers to lower costs and provide better services for end consumers. Note: If Ofgem covers all our customers affected by outages in its common ODI, we would expect to withdraw this proposal.	We propose a target, for all our customers and stakeholders affected by outages, that starts at 7.7 in 2021-22 increasing to 7.9 in 2025-25. The target starts at a score 0.1 above our average performance in the three most recent years. The target ends at a score that is the highest score we have ever achieved. Customer expectations tend to increase over time so the same score becomes harder to achieve each year.
Accelerating low carbon connections	The purpose of this ODI is to encourage us to deliver connection earlier to get new generation onto our network clearly bringing forward the benefits of low-carbon generation and more competition in the wholesale electricity market. This ODI help supports the drive towards achieving the UK's target of net-zero greenhouse gas emissions by 2050.	We are proposing two different ways of setting the target for new and existing customers: • Existing customers: we propose that for customers with existing contracts the baseline for this ODI is the date in the contract. • New customers: we propose that the target is based on the common energy scenario average delivery time for generation connections of approximately 64 months, which might need adjusting for the particular type of customer.

Our commitment to reducing sole use connection costs

For our customers that would like certainty in their connection costs, they can choose the fixed option that currently exists. For those customers who would like reduced connection cost, we would like to be incentivised to reduce the connection costs and share the risk. In order to facilitate this proposal, we will need to make some changes to the existing frameworks and work with Ofgem to create a unit cost allowance for the sole enabling elements because this will ensure the incentives uses a fair baseline is set. The incentive will be to deliver the sole enabling works lower than the UCA. We will align the sharing factor based on Ofgem's TIM as we believe this would be adequate for the risk that we will bear.

We would like to move the connection cost element, which are currently part of the excluded services into the main price control and extend the totex incentive mechanism to accommodate this.

5.2 Our proposal to make a step change in improving the system access experience

We have to take parts of the network out of service from time to time to maintain, improve and replace ageing assets. These 'outages' allow us to provide a good-quality service to all our customers in the long term through ensuring the reliability and health of the transmission system. Whilst this may cause short-term disruption it is essential to allow works to be carried out safely.

We are already acting on our customers' feedback. We are currently producing detailed outage and resource plans for the remainder of the T1 period. We are bundling work where possible to optimise system access and reduce disruption for our customers. We have identified Customer Ambassadors to be responsible for maintaining a good working relationship with our customers, listening to and acting on feedback and being a single point of contact for our customers. The Customer Ambassador initiative is focussed on driving quick improvements where needed and will measure how we are doing.

For the T2 period, we have undertaken a build of our outage plan. We are identifying the opportunities and risks to actively manage some of the future uncertainties for our projects and how we can minimise disruption for our customers.
Our approach to planning outages is that we produce long-term plans that develop into more detailed plans at the year ahead of delivery, when there is greater

certainty about the work we will need to carry out. We then manage changes with stakeholders as we build the year ahead plan and through the within-year change control processes. Our ambition is to design and implement an improved outage experience for our customers linked to our processes and system requirements. We are already developing a set of customer metrics that we will use to provide greater transparency for our customers about outages and that will enable us to improve how we manage outages.

We are looking at ways to provide greater visibility of outages and reduce the changes that occur to minimise the implications that changes to outages have for customers. Using the insight from our Customer Ambassadors' engagement, we will ensure we build a shared view of which works matter most to our customers. We are aiming to make sure we carry out our annual outage plan with minimal customer impact and that we communicate our plan and any changes to it in line with our customers' expectations.

Our approach to managing system access is directly linked to our work on whole system thinking. This is because we will be coordinating our work more closely with DNOs, generators, directly-connected customers and other parties connected to the transmission system to minimise the cost to consumers. In chapter 7 *We will enable the ongoing transition to the energy system of the future* section 5.3, we talk about our proposal to optimise across the network owner/system operator interface.

We are working with Ofgem and others to extend the connection quality survey ODI to include the satisfaction of our customers with their outage experiences. Further details on this ODI can be seen in annex NGET_ET.06 Output Delivery Incentives.

5.3 Our proposal to improve the stability and predictability of our charges

There are two elements to charges for customers:

1. Connection charges – these charges relate to assets installed solely for, and only capable of use by an individual user and are treated as excluded services within the regulatory framework.
2. Transmission Network Use of System (TNUoS) charges – these charges recover the costs of installing and maintaining the electricity transmission system that serves all network users.

We recognise that changes to our charges can have an impact on customers. There are several reasons why charges can change, but most of the volatility in network charges arises from the methodology used to calculate them, as set out in the Connection and Use of System Code (CUSC). As with other Transmission Owners, NGET is not a party to this code and therefore is unable to propose changes. We have proposals to improve stability (and therefore certainty) of charges, and the transparency of these, for the elements that we are able to influence. However, we do have ideas on how the price control framework can be improved to reduce the volatility of our revenue and therefore charges.

i) Improving how our charges reflect our costs

To improve the cost reflectivity of our charges, we are looking to improve the design of the existing uncertainty mechanisms, in particular the unit cost allowances that adjust the amount of money we can recover from or must return to our customers to reflect the work we must carry out. We want to make these more reflective of our costs. To achieve this, we are carrying out a detailed review of the triggers of infrastructure costs and are using the results to inform alternative designs for both the generation and demand connection volume drivers. Our commitment to reducing cost for sole enabling connection costs will also support this.

ii) Improving the stability of our charges

To improve the stability of our charges, we are looking at the scope for enhancing the general design and operation of uncertainty mechanisms. Some features of the current design have meant our allowance has been unnecessarily volatile, which has created volatility in our charges. We are currently considering whether the changes uncertainty mechanisms make to our allowances should reflect changes in our best forecast of output delivery, as opposed to when output is delivered. This should help smooth the effects of the uncertainty mechanism on our charges to customers. We will work with Ofgem to take forward this approach. For further details refer to annex NGET_ET.12 Uncertainty Mechanisms.

iii) Improving the transparency of our connection charges

We will also be clearer about our connection charges in advance. If our charges are likely to change, we will discuss this with customers in advance and explain the reasons behind this. We will enable customers to view the latest information on your charges using the new customer portal. This will allow them to see and understand information about their charges, this aligned with what customers have told us as detailed in chapter 13 *We will be transparent about our performance.*

6. Our proposed costs for the T2 period

In summary, our proposed costs for delivering against our proposals for the T2 period are detailed within table 8.18, below. Further justification on how these costs have been benchmarked, and how our operational expenditure has been assessed as efficient is detailed within the chapter 14 *Our total costs and how we provide value for money*

Table 8.18 Proposed baseline costs for the T2 period***

Baseline cost	21/22	22/23	23/24	24/25	25/26	Total T2	Annual T1	Annual T2	Subject to native competition	Internal historical benchmarks	External historical benchmarks	Subject to UM
Generation connections*	30.5	29.9	34.6	82.2	67.8	245.0	86.6	49.0	✓	✓	✓	✓
Demand connections*	31.6	53.9	25.9	12.6	17.7	141.7**	81.8	28.3	✓	✓	✓	✓
IT Investment	1.7	2.4	2.4	1.7	1.7	9.9	1.3	2.0	✓	✓	✓	N/A
Opex	4.0	4.0	4.0	3.9	4.1	20.0	5.6	4.0	N/A	✓	✓	N/A
Sub total	67.8	90.2	66.9	100.4	91.3	416.6	175.3	83.3	Cost certainty: High confidence			
Pension allocation						0.7						
Total						417.3						

* includes connection costs that are treated as excluded service within the regulatory framework.
** We anticipate £1.3m of capital contribution that is paid directly by customers which has been netted off the connection costs.
***Business Plan Data Table Reference: Load related expenditure worksheets contained in section B -B0.7, B4.2a, B4.2c, B4.4b, B4.5, B4.5a, B4.6, B4.7, B4.8
IT Investment 4.3a – Non- ops capex Opex D4.5 - closely associated indirects

Figure 8.19 Expenditure profile across the T1 and T2 period

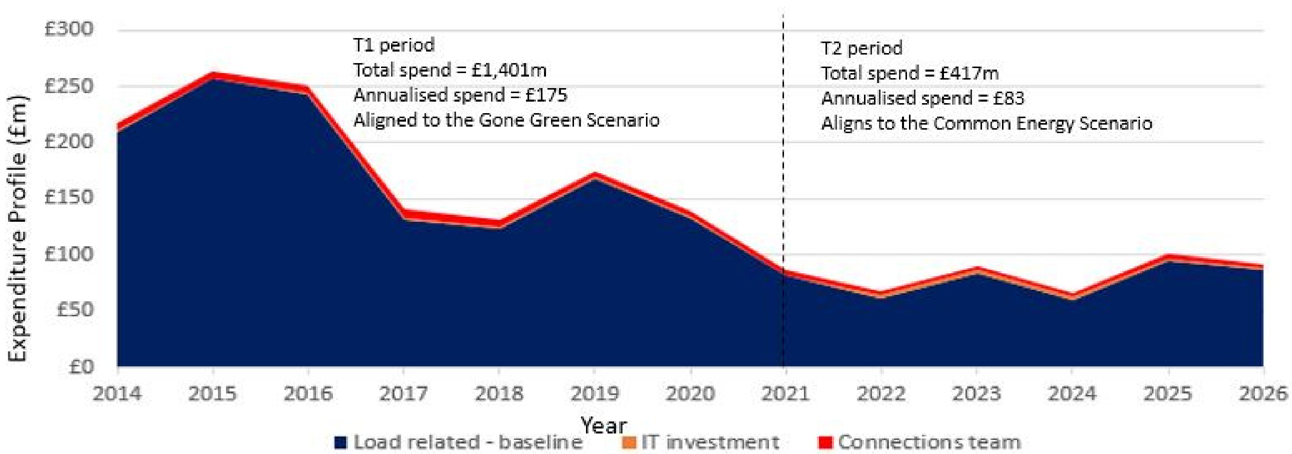


Figure 8.19 illustrates the expenditure profile for this priority over the T1 and T2 periods. Proposed annualised expenditure is 53% less in T2 than T1 (£83m vs. £175m).

7. How we will manage risk and uncertainty

We have built our plan with a focus on protecting consumers from risks in both the longer term (beyond the T2 period) and the medium term (within the T2 period).

Longer term risk: under-utilisation of assets
In the longer term, the main risk is potential under-utilisation of assets on our network. We have mitigated this through extensive analysis and stakeholder engagement, confirming the ongoing need for electricity transmission in the most highly decentralised futures. We also minimise the risk of under-utilisation of assets by ensuring each investment is accompanied by a strong need case. The signals we receive from our customers about their future requirements through the commercial arrangements (i.e. the Connection and Use of System Code).

We protect consumers for the risk of under-utilisation of assets by holding securities for customers that intend to connect. For generation projects customers commit to paying TNUoS for a number of years, for demand connections the cost of assets are mostly collected directly from the customer through excluded services.

Medium term risk: cost and volume uncertainty in an ex-ante price control
In the medium term, one of the main risks is uncertainty over cost and volumes of work in an ex-ante price control. We mitigate this by only including the most certain costs in our baseline plan and proposing uncertainty mechanisms that allocate risk to whomever is best placed to manage it.

Our plan is consistent with the minimum values in the Energy Networks Association (ENA)'s Common Energy Scenario and therefore relies on uncertainty mechanisms to deliver for customers and enable net zero by 2050.

Consumers can best manage uncertainty about the route to net-zero emissions because the route will reflect changes in their behaviour. We are best placed to manage uncertainty over the costs of achieving the outputs consumers want because we can efficiently control our costs.

We are protecting consumers by only including the most certain costs in our baseline plan and proposing an uncertainty mechanisms that allocate risk to whomever is best placed to manage it.

Our plan is consistent with the minimum values in the Energy Networks Association (ENA)'s Common Energy Scenario and therefore relies on uncertainty mechanisms to deliver for customers and enable net-zero by 2050.

With the market continuing to rapidly evolve, the ongoing development of whole system solutions, growing system operability requirements and network competition, a more complex uncertainty landscape exists in the T2 period, requiring an evolution of the T1 approach.

In developing our proposals, we have ensured mechanisms:

i. change our allowances if customers' needs change during the T2 period so that we can invest in the outputs they need,
ii. allow whole system solutions to be identified and delivered during the T2 period,
iii. retain the incentive for us to reduce our costs and share the cost savings with consumers.

We have worked with external experts to develop an enhanced suite of uncertainty mechanisms, building on the existing T1 approach of unit cost allowances and the experience of the operation of these mechanisms.

To manage uncertainty for this priority, we propose:

- re-design of the generation and demand volume driver to ensure they are in line with the observed changes in our customer base and make the unit cost allowances more cost-reflective;
- develop a new volume driver for network investment driven by embedded generation; and
- work with Ofgem to improve the uncertainty mechanisms so that they lead to smoother adjustments in our allowances and more stability in our charges to customers.

A rigorous and comprehensive econometric approach was used to develop our proposals, as shown in figure 8.20 below, which are a critical component of our overall business plan and are evidenced against Ofgem's business plan guidance criteria in table 8.21.

The detail of our analysis and proposals to manage energy supply and demand uncertainty is set out in annex NGET_ET.12 Uncertainty mechanisms, NGET_ET.12A UM Snapshot table, BPDT D.18 Bespoke Uncertainty and accompanying workbooks showing the detail of our development and statistical analysis.

Figure 8.20 Econometric approach used to develop proposals

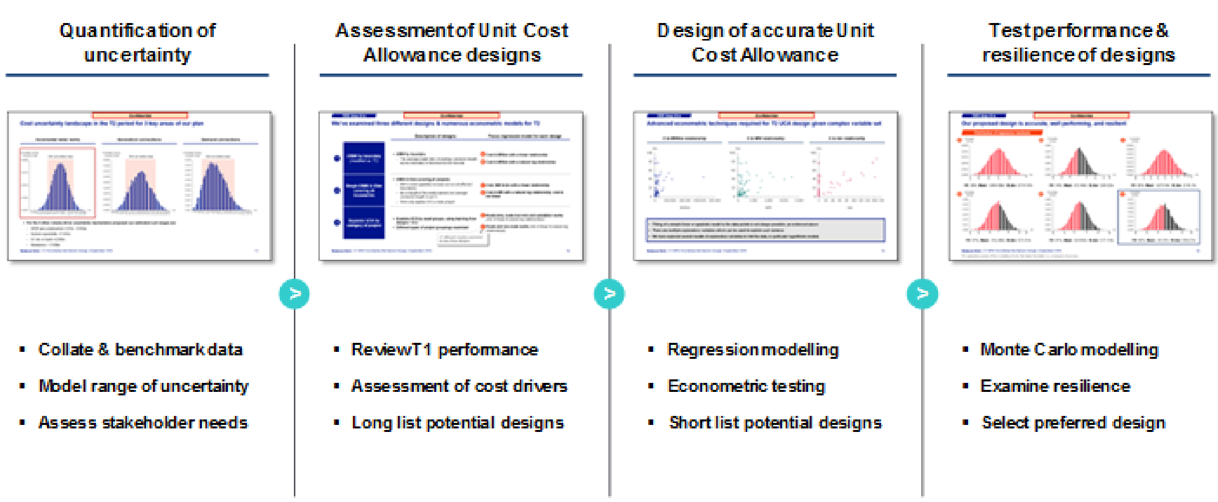


Table 8.21 Proposed uncertainty mechanisms and justification

Generation Connections – Unit Cost Allowance (UCA) – Volume Driver

Key stats:	No.
Models considered	8
Input data points (projects)	57

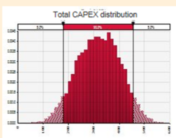
Uncertainty characteristics

i) Risk and ownership

- Customer need and associated type of connection and extent of works are uncertain
- Requirement driven by changing customer activity
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Estimated range of uncertainty is £277m *(90% of the Monte Carlo simulations guided by the Future Energy Scenarios have a total cost between £178m and £455m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

iii) Frequency and probability

- A minimum frequency of annually
- Near 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- Per kW, per circuit-km UCAs – Reducing allowances by >£970m as system needs changed
- Substation cost volume driver UCA is not cost reflective of applications for connections capacity shift towards <100MW
- The overall mechanism has also not been reflective of network upgrades required beyond the connecting substation

ii) Learnings for T2

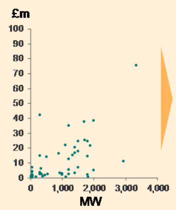
- Mechanism should reflect evolving customer base by accommodating for:
  - smaller connection sizes
  - cost of beyond substation enabling
  - alternative connection solutions, such as tertiary winding connections
- A more cost-reflective UCA designed by rigorous statistical analysis would better protect consumers
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed approach and benefits

- Separate UCA for AIS *vs.* GIS sites, and then further split by new and existing sites and whether the connection is above or below 100MW
- New UCAs are designed using established statistical techniques and stress-tested using Monte Carlo simulations to ensure accuracy and resilient UCA

Inputs (£m vs. MW)



Proposed Design

Substation (sub) Costs – MW connected at:

- new AIS sub: [redacted] £m/MW
- existing AIS sub <100MW: [redacted] £m/MW
- existing AIS sub >100MW: [redacted] £m/MW
- new GIS sub: [redacted] £m/MW
- existing GIS sub <100MW: [redacted] £m/MW
- existing GIS sub >100MW: [redacted] £m/MW

- Beyond Sub. Circuit Upgrade Costs – [redacted] £m/circuit km
- New Overhead Line Circuits – [redacted] £m/circuit km
- New Underground Cable Circuits . [redacted] £m/circuit km

Testing (cost vs. allowance)

Mean: £0.78m

Std. Dev.: £22.98m

ii) Drawbacks and mitigations

- Additions to the mechanism outweighed by significant increase in cost-reflectivity and mitigated through providing greater clarity on which assets the UCA is covering

Demand Connections – Unit Cost Allowance (UCA) – Volume Driver

Key stats:	No.
Models considered	9
Input data points (projects)	33

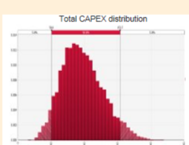
Uncertainty characteristics

i) Risk and ownership

- Customer need, associated type of connection and potential whole system alternatives are uncertain
- Requirement driven by changing customer activity
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- Estimated range of uncertainty is £147m *(90% of the Monte Carlo simulations guided by the Future Energy Scenarios have a total cost between £54m and 201m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

iii) Frequency and probability

- A minimum frequency of annually
- Near 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- UCA per SGT and per km of OHL – reducing allowances by >£185m as system needs changed
- Substation UCA could have been more cost reflective of the projects delivered. It was based on shared infrastructure sites for connection; but the volume of higher cost single customers connecting has increased
- We delivered several connections without the need for an SGT; not triggering allowance but incurring cost

ii) Learnings for T2

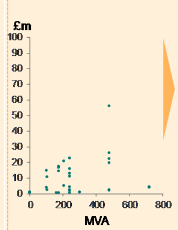
- UCA should reflect evolving customer:
  - e.g. demand from industrial facilities decline, while demand from data centres rises
  - reflect lower cost, innovative connection solutions, such as tertiary winding connections
- A more cost-reflective UCA designed through rigorous statistical analysis would better protect consumers and companies
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed approach and benefits

- Separate UCA for connection and infrastructure sites
- Connection sites UCA split by new *vs* existing and new <50MVA
- Infrastructure sites UCA split SGT *vs.* no SGT requirement
- The new UCAs are designed using established statistical techniques and stress-tested using Monte Carlo simulations to ensure accuracy and resilience
- Revenue calculated based on latest 5-year RRP forecast of outputs in order to minimise customer charging volatility

Inputs (£m vs. MW)



Proposed Design

Substation (sub) costs

Connection Projects

- Capacity delivered at new subs: [redacted] £m/MVA
- Capacity delivered at existing subs: [redacted] £m/MVA
- Capacity delivered at new sub < 50MVA: [redacted] £m/SGT

Infrastructure Projects

- New SGT delivered: [redacted] £m/SGT
- No SGT required: £[redacted]m

New circuit details in Annex ET.12

Testing (cost vs. allowance)

Mean: -£4.27m

Std. Dev.: £22.58m

ii) Drawbacks and mitigations

- Additions to the mechanism outweighed by significant increase in cost-reflectivity and mitigated through providing greater clarity on which assets the UCA is covering

Embedded Generation (Low Voltage Rebuild) – Unit Cost Allowance (UCA) – Volume Driver

Key stats:	No.
Models considered	3
Input data points (projects)	12

Uncertainty characteristics

i) Risk and ownership

- Both system need and the most economic solution (i.e. potential transmission alternatives) uncertain
- Requirements driven by working with ESO & DNOs taking a whole systems view of system requirements
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality

- A total range of uncertainty of >£105m is estimated in the Common energy Scenarios; baseline of zero

iii) Frequency and probability

- A minimum frequency of annual aligned DNO demand data submission
- 100% probability of some change in future requirements

T1 experience and learning

i) T1 experience

- Allowance of 9 sites for circuit breaker replacement, during the mid-point review this was updated to replace 1 circuit breaker.
- Taken a whole system approach with the DNOs to determine investments

ii) Learnings for T2

- Continue to take a whole system approach when determining investment requirements
- UM required to give allowances when transmission has been identified as the best solution for consumers
- A more cost-reflective, output based UM would better protect consumers and companies

T2 proposals

i) Proposed approach and benefits

- Unit cost allowance would trigger upon completion of a whole system assessment with the DNO and identification of a transmission solution as most economic for consumers
- [redacted] £m/substation for each new substation required
- Existing substation – [redacted] £m/substation fixed cost allowance (bay refurbishment, database changes and substation control system)
- Allowance of items selected from menu when individual assets require replacing (e.g. circuit breakers)

Bay type	£k/circuit breaker
LV 132kV (AIS)	[redacted]
LV 132kV (GIS)	[redacted]
LV 275kV (AIS)	[redacted]
LV 275kV (GIS)	[redacted]
HV 132kV (AIS)	[redacted]
HV 132kV (GIS)	[redacted]
HV 275kV (AIS)	[redacted]
HV 275kV (GIS)	[redacted]
HV 400kV (AIS)	[redacted]
HV 400kV (GIS)	[redacted]

ii) Drawbacks and mitigations

- Additional complexity mitigated by opportunity provided by automatic allowance adjustments to discover whole system solutions through the price control period, reducing costs