Investment Decision Pack

NGET_A7.08 System Operability (Voltage)

As a part of the NGET Business Plan Submission

nationalgrid

Justification Paper
Load Related – System Operability (Voltage)

Primary Investment Driver	Maintain system voltages within limits specified in the NETS SQSS
Reference	NGET_A7.08 System Operability (Voltage)
Location in main submission narrative	Chapter 7 – *Enable the ongoing transition to the energy system of the future* Section 5.3 – i) *Optimise across the network owner / system operator interface (part c)* & Section 5.3 ii) *Optimise across the transmission / distribution interface*
Cost	£30.7m
Delivery Year(s)	2021 - 2026
Reporting Table	B series tables and totex cost-matrix tables
Outputs in the T2 period	[redacted] 400kV 200MVAr Reactors

Spend Apportionment		**T1**	**T2**	**T3**
	Reactors	£103.9m[1]	£30.7m	N/A

All costs are in 18/19 prices, unless otherwise stated.

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[1] As reported in NGET's 2018/19 RRP

Executive Summary

Reactive power is a naturally occurring phenomenon of all AC power networks. Due to the changing characteristics of GB electricity network and its customers, demand for reactive power has been steadily decreasing over the last ten years. This trend is forecast to continue in the T2 period across all scenarios.

The reducing demand for reactive power, resulting from decentralised generation and changing consumer load types, leads to a surplus of reactive power. This surplus causes system voltage levels to increase under certain network conditions. High voltages can cause damage to equipment and safety issues.

Transmission owners are obligated to design our network such that voltages will stay within the planning limits specified in the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS or SQSS). It is a condition of our licence to design our network in compliance with the requirements of the SQSS.

Reactive power compensation devices known as 'reactors' are the primary Transmission Owner (TO) investment solutions for absorbing surplus reactive power and maintaining system voltages within SQSS limits.

We have forecast future reactive compensation requirements across the T2 period against the Common Energy Scenario background. This assessment showed a need for ~35 TO reactor investments to maintain system voltages within SQSS planning limits.

Collaborative working between TOs, DNOs, and the ESO (as part of the Electricity Networks Association Open Networks project), has been ongoing since 2017 to develop processes and methodologies to identify and assess whole system options for managing high voltage issues.

In line with the objectives of the Open Networks project, we expect these whole system processes to become business as usual in future and to be formally incorporated into collaborative planning processes such as the ESO's annual Network Options Assessment.

To facilitate this emerging whole system approach, we propose that our baseline investment plan includes [redacted] initial TO reactor investments to resolve the most pressing voltage issues identified in the collaborative ENA assessment – *The High Voltage Case Study*. These investments would be delivered in the first year of the T2 period.

Any further TO investment requirements identified through whole system assessments during the T2 period would be facilitated by a volume driver uncertainty mechanism (UM). Similarly, this UM could act to return the baseline funding if whole system options are found to offer greater value than our proposed baseline investments.

This paper justifies the inclusion of £30.7m in our baseline plan for the T2 period to deliver [redacted] inductive reactive compensation devices (reactors) to meet forecast system requirements in the first two years of the T2 period.

The forecast requirements were determined through collaborative whole system approach involving the ENA, ESO, NGET, and DNOs. These investments, and the ongoing whole system approach proposed, ensure we fulfil our licence obligation to maintain compliance with the SQSS and facilitate the transition to a zero-carbon electricity system by 2025 and the meeting of net-zero 2050 legislated targets at lowest cost to consumers.

Engagement outcomes: Our engagement with stakeholders, including the ESO, our independent Stakeholder Group and the RIIO-2 Challenge Group has led to some very clear priorities: (i) that a whole system approach to these investments is crucial to minimise costs for consumers, (ii) that there is too much uncertainty to establish all requirements across the entirety of the T2 period in advance and (iii) that we should be ready to deliver if a transmission solution is deemed most economic.

Whole system approach: The ESO's Network Development Roadmap *pathfinding* projects and the nascent Regional Development Programmes approach will eventually provide a framework that systematically discovers whole system solutions to system operability issues. This framework is still evolving through the ENA's Open Networks Project, so we have undertaken extensive bilateral engagement with the ESO and DNOs in England and Wales to produce a whole system draft business plan, in lieu of an agreed framework. Through taking this whole system approach, our proposed baseline investment of £30.7m is **more than £184m less than it otherwise would have been** (i.e. [redacted] reactors, rather than a minimum likely requirement of [redacted] in the T2 period).

Further investments, beyond those identified in our baseline plan, are highly likely to be required during the T2 period. However, in line with our commitment to ensuring the best whole system solution is delivered for consumers we have proposed minimal baseline funding and commit to proactively engaging in an ongoing whole system assessment process to resolve system operability issues throughout the T2 period. **More details are available in Chapter 7 of the main business plan narrative and NGET_ A7-8.03 Whole Systems Annex.**

Managing Uncertainty: The ESO and RIIO-2 Challenge Group have indicated they are keen to ensure we can deliver a transmission solution to future system operability issues, where this is deemed best for consumers through a whole system process. To facilitate this, we propose a new volume driven uncertainty mechanism, based on a unit cost allowance(s) that would automatically adjust our baseline allowance (up or down). This protects consumers from uncertainty whilst ensuring we can play our role in facilitating the operation of a zero-carbon system by 2025. Our proposals for uncertainty mechanisms are **detailed in ET.12 Uncertainty Mechanism Annex.**

1. Introduction

1.1 Reactive Power and Voltage Limits

Reactive power is a naturally occurring phenomenon within all AC power systems and is vital in allowing an AC system to operate.

Reactive power and system voltage are directly linked with increases in reactive power levels causing voltage to increase and reductions in reactive power causing voltage to reduce.

The National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS or SQSS) specifies limits within which system voltages must be maintained. Limits are specified for both planning activities (e.g. transmission owners assessing future network performance and requirements) and operational activities (e.g. the ESO operating the system on a minute by minute basis). As a TO we must design our network in such a way that voltages can be retained within the planning limits. The emergence of whole system options and an increased focus on cost benefit analysis of investments, means that we now factor more steps and additional stakeholders into our design process.

Chapter 6 of the SQSS sets out the pre-fault and post-fault voltage planning limits within which the system must perform. The following extract from the SQSS shows the planning limits as applicable to NGET:

Table 6.1 Pre-Fault Steady State Voltage Limits and Requirements in Planning Timescales

(a) Voltage Limits on Transmission Networks		
Nominal Voltage	Minimum (***Note 1***)	Maximum
400kV	390kV (97.5%)	410kV (102.5%) ***Note 2***
275kV	261kV (95%)	289kV (105%)
132kV	125kV (95%)	139kV (105%)

Table 6.2 Steady State Voltage Limits and Requirements in Planning Timescales

(a) Voltage Limits on Transmission Networks		
Nominal Voltage	Minimum	Maximum
400kV	380kV (95%) ***Note 3***	410kV (102.5%) ***Note 4***
275kV	248kV (90%)	289kV (105%)
132kV	119kV (90%)	139kV (105%)

The limits specified in the SQSS are intended to achieve a balance between the investment cost to achieve compliance, security of supply, and the operational costs incurred by the ESO to manage system voltage using commercial services.

Voltages dropping below the lower limits can cause mal-operation or damage to network assets and customers' equipment. The worst-case effect of low voltage conditions would be a system wide voltage collapse that would result in a nationwide blackout. Investment in reactive compensation assets prevent this occurring and, as a last resort, protection systems are in place that would take automatic action to prevent such a voltage collapse.

Voltages exceeding the upper limits can result in mal-operation or damage to network assets and customers' equipment and safety issues.

High system voltage is considered to be the primary risk that must be addressed in the T2 period (see Section 1.2 for further details).

Two primary methods are used to manage high voltage conditions and maintain transmission system voltages within the SQSS limits:

- TO investment in inductive reactive compensation assets and,
- ESO paying generation customers to alter their absorption of reactive power

Measures taken by the ESO such as switching out certain transmission circuits can also help to manage high system voltages but are considered secondary measures due to their limited effectiveness and effect on system integrity.

1.2 Trends in Reactive Power Demand

There has been significant change in total reactive power demand seen by the transmission system between 1998 and the present day. Figure 1 shows the cumulative reactive power (MVAr) demand at times of maximum and minimum active power (MW) demand.

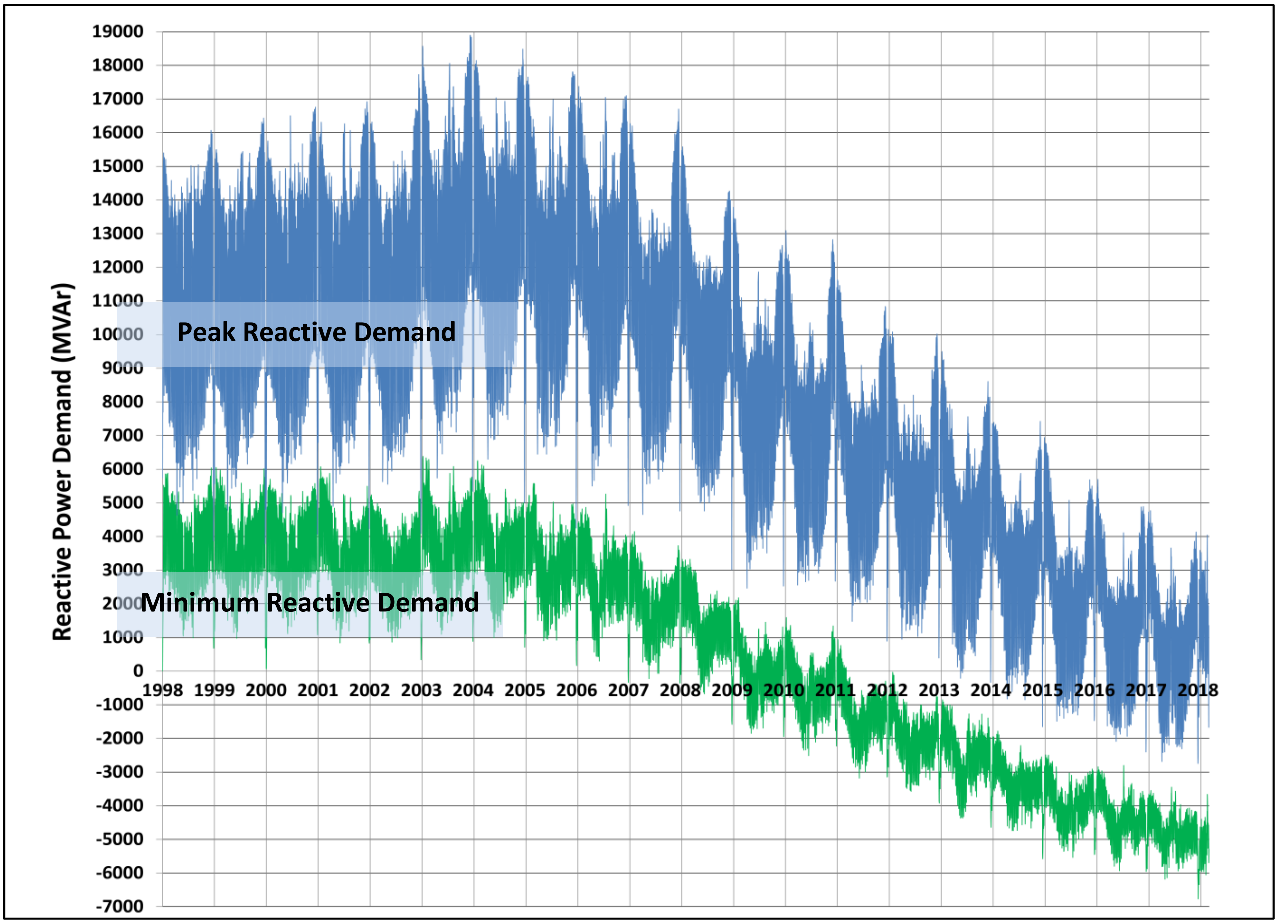


Figure 1 – National reactive power demand at times of system maximum and minimum MW demand 1998 - 2018

Between 1998 and 2007, reactive power demand under minimum MW demand conditions (green trace) was relatively consistent, with a low of approximately 1GVAr. During maximum MW demand conditions (blue trace), there was a slight increase in the maximum reactive demand from 1998 to 2005 from approximately 16GVAr to 19GVAr, which dropped back to 17GVAr by 2007.

Between 2008 and present day, total reactive demand has declined with a linear trend, by approximately 7.5GVAr during system minimum conditions (green trace), from 1GVAr to -6.5GVAr. This negative reactive power demand represents the distribution networks exporting reactive power at GSPs onto the transmission system, i.e. a reversal of reactive power flow direction.

The total decline in reactive demand has been even higher at times of maximum MW demand (blue trace) than that observed during system minimum conditions, dropping approximately 13GVAr from 17GVAr to 4GVAr between 2008 to present day.

There are 4 primary causes for this trend:

- Changes in consumer technology
  - o Reduction in inductive technology that absorbs reactive power such as Cathode Ray Tube (CRT) TVs and filament light bulbs
  - o Increase in capacitive technology that generates reactive power such as LCD/LED TVs, LED light bulbs and devices requiring power electronic converters such as laptops, tablets and smart phones.
- Increased embedded generation
  - o This has lowered net real power demand from the transmission system, increasing the capacitive effect of the network (system gain) as it is required to carry less power.
  - o Increased volume of cables on DNO networks often used to connect embedded generation (cables naturally generate reactive power due to the physical properties of their construction)
  - o The lack of a power factor control requirement for embedded generators. Transmission connected generation is required to be able to control the level of reactive power the output or absorb. This requirement does not apply to the vast majority of embedded generation. As embedded generation has started to replace transmission generation this has reduced the contribution made by the generation sector to voltage management
- Decline of UK manufacturing industry such as factories and steel works, all of which were predominantly inductive loads (i.e. these customers acted as a demand for reactive power and indirectly helped to prevent the reactive power surplus observed today)
- Natural effect of network assets
  - o Cables naturally generate reactive power (due to their physical construction), the increased use of underground cables circuits, particularly in DNO networks has increased the levels of reactive power across the system.
  - o The increase in embedded generation and increase in energy efficient technology has lowered real power demand, meaning the volume of power flowing on the transmission system has reduced at certain times. This “light loading” (i.e. circuits only carrying a small amount of their capacity) increases the effect of the inherent natural capacitance in the network. This effect is known as system gain and can be summarised as follows: the more power transmission circuits are carrying the more reactive power they will absorb, when circuits are lightly loaded they will absorb less (or even generate) reactive power. This again contributes to the drop in reactive demand and the surplus under system minimum demand conditions.

This trend leads to a surplus of reactive power on the transmission system that causes voltages to increase. This is particularly prevalent during minimum demand periods (e.g. summer time) when the surplus is so great as to cause system voltages to exceed the SQSS limits in some areas on the network.

As described earlier, a surplus of reactive power causes system voltage levels to increase. If the voltage becomes too high or too low this may cause damage or mal-operation of both network assets and customer equipment.

There is a consensus across the electricity industry that high voltage management is a growing issue. This is evidenced by the operational expenditure already being incurred by the ESO to manage system voltages and the collaborative projects that have recently been undertaken by network companies.

ESO spending on ad hoc reactive power balancing actions in 2018/19 was ~£23.4M. The cost of reactive power utilisation was £81.7m. This does not include the costs of contracted reactive power service provision as these are not currently published by the ESO. However, discussion with the ESO has indicated that these contracted services account for additional costs of >£10M per annum.

Collaborative projects such as the *High Voltage Case Study* have been initiated through the Electricity Networks Association (ENA) Open Networks project. This project seeks to assess and compare various network and customer solutions to high voltage issues.

2. Experience in RIIO-T1

Our RIIO-T1 baseline plan included 11 reactor investments. Throughout the T1 period the factors described above have exceed the forecasts available at the time our T1 plan causing system voltage issues to be far more onerous and wide spread than predicted.

In response to the high voltage management issues that have emerged over the T1 period, we expect to deliver [redacted] reactors at a total cost of £103.9m by the end of the T1 period.

Due to the sensitive nature of system voltage requirements, these investments have been delivered in stages (referred to as Tiers) to minimise the risk of sub-optimal decisions. Two separate Tiers of investment (1 & 2) have been delivered in T1.

Based on our assessment of T1 reactive power requirements a third phase of reactor investment was planned, the Tier 3 reactor investments. This proposed an additional 6 reactors in the northern area of the England and Wales transmission system.

However, during the T1 period the management of system high voltage has been identified as a key area where whole system options could, in some cases, offer alternatives to transmission investments. These alternative solutions include the following:

- DNOs installing reactive compensation equipment on their network to manage GSP reactive power import / export to the transmission system
- Embedded generation customers providing reactive power control services similar to those provided by transmission connected generators
- Commercial contracts between the ESO and customers to provide reactive power services

A number of collaborative projects, involving TOs, DNOs, DSOs, the ESO, and customers, have been undertaken in the last few years to investigate the options available and the methodologies by which these can be assessed.

The most notable of these (when considering future TO investment plans) is the *High Voltage Case Study*. This collaborative project was undertaken as part of the ENA Open Networks project and is seeking to develop and test the process and methodology for identifying network reactive compensation requirements and compare the cost benefit delivered by each available solution (TO, DNO, customer) to determine which offer the greatest value for consumers.

During the T1 mid-period review, we raised the issue of reactive compensation investments to manage high voltage conditions. Ofgem responded by requesting that we investigate whole system alternatives to transmission reactor investments.

Ongoing engagement between us and the ESO (outside of the ENA case study) has resulted in the ESO requesting that 1 of the [redacted] Tier 3 reactor investments is delivered prior to the end of the T1 period to mitigate existing operational costs and protect consumers. The remaining [redacted] Tier 3 reactor investments were placed on hold to facilitate a whole system assessment through the *High Voltage Case Study*.

The case study has not yet concluded. Interim results were published by the ENA Open Networks project in December 2018[2]. The ESO is continuing to assess commercial options and formal results and recommendation will be published once this process is complete.

The proposed process and methodologies developed by the case study have now been adopted by the ESO as part of its annual NOA process and were included as part of the ESO's published 2019/20 NOA methodology[3]. An example of this is shown in Figure 2.

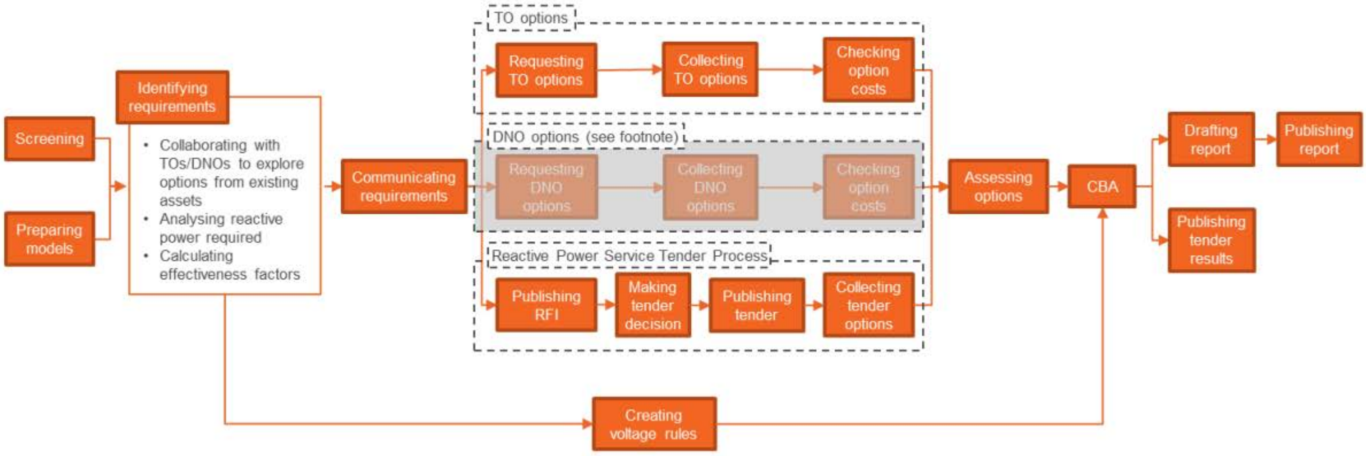


Figure 2 – Overview of the High Voltage Management Process

It is our expectation that all future reactive compensation investments required to manage high voltage conditions will be identified and assessed through this collaborative whole system process.

3. Forecast Reactive Power Requirements for RIIO-T2

The trends described in Section 1 are forecast to continue during the T2 period and beyond. The Common Energy Scenario for the T2 period assumes continued growth of embedded generation (particularly power inverter connected wind and solar) and there is industry consensus that investment or operational expenditure will be required to manage high system voltage conditions within the limits specified in the SQSS.

Quantifying exact future reactive power requirements is complex due to the number of factors that can influence reactive demand levels. The nature of consumer technology, the characteristics of the network infrastructure, embedded generation activity, and the operational running arrangements of the ESO (and DSOs in future) will all influence reactive power demand and hence system voltages. Many of these factors can vary on a day to day basis and hence accurately predicting specific long-term investment requirements is difficult.

However, it is possible to indicatively assess future network reactive power requirements to provide a guide to the potential volume and location of investment requirements.

To inform our T2 planning process we have assessed indicative long-term reactive power needs using the Common Energy scenario and have also sought to identify more certain short-term needs through the work carried out in the ENA *High Voltage Case Study.*

[2]http://www.energynetworks.org/assets/files/ON-WS1-P1%202018%20Investment%20Planning%20Processes%20-%20Approach%20vFinal.pdf
[3] https://www.nationalgrideso.com/document/143311/download

1.3 Long-Term Reactive Power Requirements – Analysis of Common Energy Scenario

To create as accurate a model for assessing future reactive power requirements as possible, we worked with the ESO to create a base model that accurately re-created voltage conditions as observed during a period of system minimum demand (the most onerous conditions for high voltage issues) in September 2017.

This model was used as a base from which we could modify the network demand to reflect the minimum demand conditions forecast for 2025/26, consistent with the Common Energy Scenario. A constant ratio between active and reactive power was assumed when adjusting demand from the baseline to the 2025/26 forecasts as this is consistent with the trend observed to date (presented in Figure 1). Using this methodology, the following minimum period active / reactive power demands were calculated.

Scenario	GB Active Power Demand at System Minimum	GB Reactive Power Demand at System Minimum
ENA Common Scenario	**8.4 GW**	**- 8.1 GVAr**

Table 1 – Forecast Common Energy scenario minimum active and reactive power demand 2025/26

The negative value of reactive demand at system minimum indicates that the system is experiencing a surplus of reactive power at this time. Under these conditions, inductive reactive compensation (e.g. reactors or customers operating at leading power factor) is required to absorb this surplus reactive power and prevent system voltages increasing beyond SQSS limits.

The active and reactive demand was allocated across the various Grid Supply Point substations in line with the distribution observed in the baseline model. This approach preserved different regional requirements that exist across the network.

Against this background, transmission reactive compensation assets were added to the network model to restore compliance with SQSS voltage limits. The table below shows the number of reactive compensation assets that were required to maintain compliance with SQSS limits in each zone of the England & Wales network by 2025/26.

2025/26 Reactive Compensation Requirement SBP Scenario			
Zone	**GVAr**	**200 MVAr Reactor***	**100 MVAr Reactor***
Zone A	1.1	[redacted]	[redacted]
Zone B	0.8	[redacted]	[redacted]
Zone C	0.2	[redacted]	[redacted]
Zone D	0.2	[redacted]	[redacted]
Zone E	0.2	[redacted]	[redacted]
Zone G	0.2	[redacted]	[redacted]
Zone H	0.6	[redacted]	[redacted]
Zone J	0.2	[redacted]	[redacted]
Zone K	0.6	[redacted]	[redacted]
Zone L	0.3	[redacted]	[redacted]
Zone N	0.2	[redacted]	[redacted]
Zone P	0.6	[redacted]	[redacted]
Zone Q	1.0	[redacted]	[redacted]
Total	6.2	[redacted]	[redacted]
Total GVAR	6.2		
Total Reactors		[redacted]	

* 200MVAr reactors are assumed to be installed at 400kV, 100MVAR reactors are assumed to be installed at 275kV or 132kV.

It is assumed 200MVAr reactors would be installed until physical capacity at sites is exhausted – due to the better £/MVAr delivered compared with 100MVAr units.

This analysis provides a view of the potential volume of reactive compensation equipment that could be required over the T2 period, should the current trends in reactive power conditions continue.

Delivering these volumes of reactive compensation equipment would constitute >£[redacted]m of investment over the T2 period (see Section 5 for cost estimation).

However, it is acknowledged that the methodology applied provides only an indicative view of requirements and that specific, project by project, reactive compensation investment requirements is uncertain.

1.4 Short-Term Reactive Power Requirements – ENA High Voltage Case Study

The ENA case study sought to identify the reactive power requirements in the network for the year 2020 in order to identify the most pressing areas requiring investment.

The network models were developed collaboratively between the ESO, TOs and DNOs. Analysis was carried out primarily by the ESO.

A full description of the High Voltage Case Study methodology can be found in ENA Open Networks project report *Open Networks, Workstream 1: Product 1, Investment Planning Processes – Whole System*[4].

[4] http://www.energynetworks.org/assets/files/ON-WS1-P1%202018%20Investment%20Planning%20Processes%20-%20Approach%20vFinal.pdf

A key output of the analysis was a heat map that indicated where the most pressing reactive power requirement was across the network and what level of reactive compensation would be required to restore compliance with SQSS voltage limits. The heat map (Figure 3) is shown below.

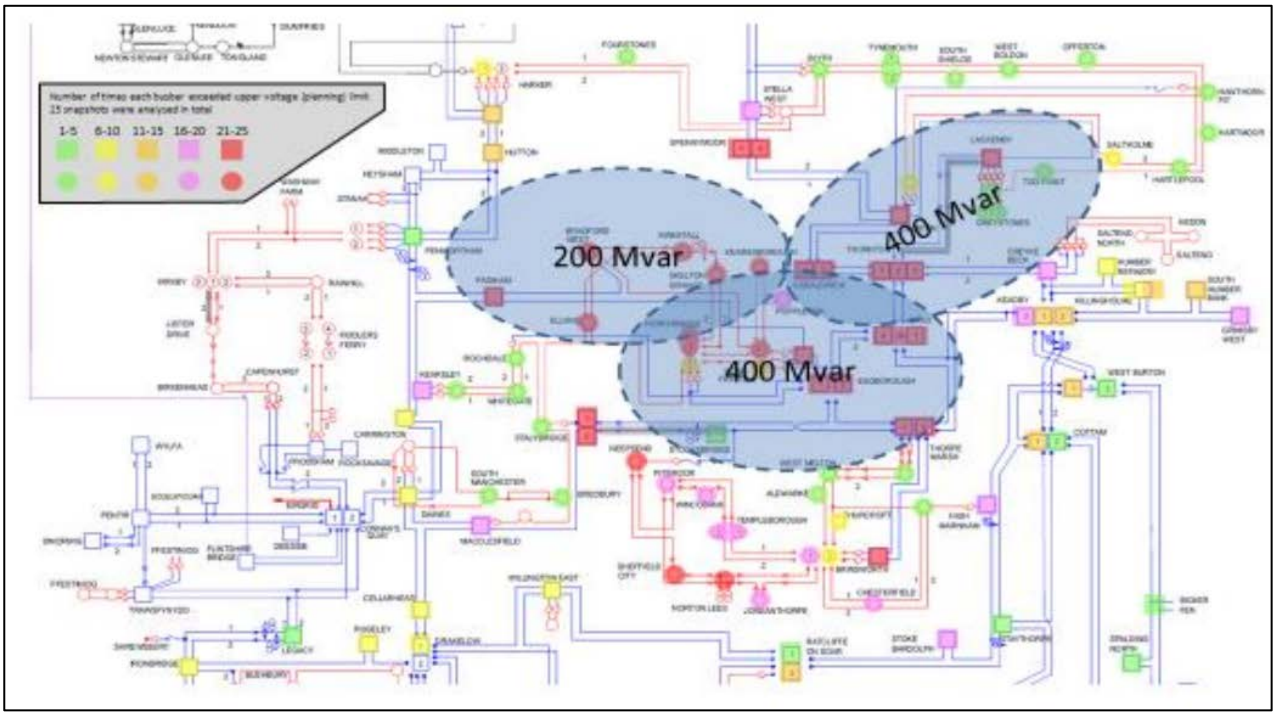


Figure 3 – Reactive Power Requirement Heatmap (Source ENA report)

1000MVAr of reactive power compensation was identified as being required in the northern area of the England and Wales transmission system in 2020.

To support the High Voltage Case Study, we submitted to the ESO 16 transmission investment options. These were a mix of 200MVAr (400kV) and 100MVAr (275kV) reactors located at sites throughout the identified area.

The individual physical characteristics of each site lead to different investment costs for each option, whereas the electrical characteristics of the local network means that the effectiveness of a reactor will also vary based on where it is installed. For example, a 200MVAr reactor installed at one site may have a greater or lesser effect on system voltage than an identical asset installed at a different location (even if this location is nearby).

Providing a range of options to the ESO allows for the most effective combination of options to be identified.

The DNOs in the identified area also submitted investment options to allow comparison between the cost and effectiveness of transmission and distribution options. In addition, the ESO is currently undertaking a Request for Information process to gain an understanding of the commercial options that may be available from customers.

The ESO's process of assessing commercial options and carrying out a cost benefit analysis against the TO and DNO options is not yet complete, although initial analysis done to compare TO investment options with DNO options has indicated that TO options provide better value than the DNO options in most cases (published in the 2018 ENA report[5]). However, we do not expect the ESO's analysis to be fully complete, and formal investment recommendations to be made, ahead of our December submission deadline.

[5] http://www.energynetworks.org/assets/files/ON-WS1-P1%202018%20Investment%20Planning%20Processes%20-%20Approach%20vFinal.pdf

4. Proposed Baseline T2 Investment Plan

The ESO is currently incurring significant system operation costs to manage system high voltage conditions that are being driven by the changing characteristics of the electricity network.

As described in 3.1 above, our analysis of total reactive power requirements over the T2 period against the Common Energy scenario has shown a continued reduction in reactive power demand and therefore a continued need for mitigating actions to maintain system voltage within the limits specified by the SQSS. Our analysis has shown that approximately 6,200MVAr of reactive power compensation, equating to 35 transmission reactor investments, would be required to maintain SQSS compliance by 2025/26.

As described in 3.2 above, the short-term analysis carried out as part of the ENA *High Voltage Case Study* has shown a need for approximately 1,000MVAr of reactive power compensation in the northern area of the England and Wales transmission in the first year of the T2 period.

The whole system processes and methodology developed through the ENA Open Networks project are beginning to be established as standard ways of working and we expect future reactive power investment requires to be assessed through this approach.

We have therefore sought to prepare a baseline investment plan for T2 that balances the need for short-term investment to protect consumers (by reducing ESO operational costs), the uncertainty over specific long-term investment requirements, and facilitates the newly emerging whole system approach to assessing voltage management options.

Due to the uncertainty over long-term needs, we **are not** proposing to include the forecast [redacted] transmission reactor investments in our baseline plan.

However, to mitigate the costs currently being incurred by the ESO, we propose to include [redacted] **reactor investments in our baseline plan**, that would be delivered in the first year of T2, to meet the short-term requirements identified through the ENA *High Voltage Case Study.*

Our previous Tier 3 reactor investment plan, that was paused to allow the ENA case study to undertake a whole system assessment, proposed delivery of [redacted] transmission reactors in the northern area of the England and Wales transmission network. All of those proposed investments fall within the area identified by the ENA case study analysis. These investments were submitted as part of our input to the *High Voltage Case Study* for assessment alongside DNO and commercial options.

It should be noted that our development of Tier 3 investment options included consideration of alternative solutions such as adding circuit breakers into circuits that contained cable sections allowing for these reactive power generating cables to switch out with less impact on the wider network. However, these alternative approaches were found to offer less cost benefit than investments in reactors.

These Tier 3 reactor investments form our proposed baseline investment plan and are summarised in Table 3.

Proposed Tier 3 Investment Location	Scope
[redacted]	

Table 3 – Proposed Tier 3 reactor investments

We propose that a volume driver uncertainty mechanism is included in our T2 price control arrangements to provide funding for any additional TO reactor investments that are identified through the whole system assessment process during the T2 period. Similarly, this uncertainty mechanism would serve to reduce our baseline funding should fewer than [redacted] transmission reactor investments be required over the T2 period.

This approach reflects our commitment to the development of whole system solutions, ensuring options that address high voltage conditions and system stability at lowest cost to consumers are delivered, regardless of provider.

This ongoing collaborative process will allow solutions from DNOs, DSOs, customers, and the ESO to be compared against transmission investments before we commit to an investment decision. More details are available in Chapter 7 of the main business plan narrative and the NGET_A7-8.03 Whole Systems Annex.

The cost of our baseline investments is explained in Section 5.

Further details of our uncertainty mechanism proposal are included in Section 7.

5. Cost Estimation for Baseline Investments

1.5 Project Development

National Grid established the Network Development Process (NDP) to ensure a consistent approach to project development is applied to all investments (the same process applies to customer-driven and asset health-driven investments) and provide a rigorous governance framework to ensure the right development activities are undertaken at the right time, before moving on through the process and incurring additional costs. The process is characterised by stages of activity (boxes) and governance gates (diamonds), as shown in Figure 4.

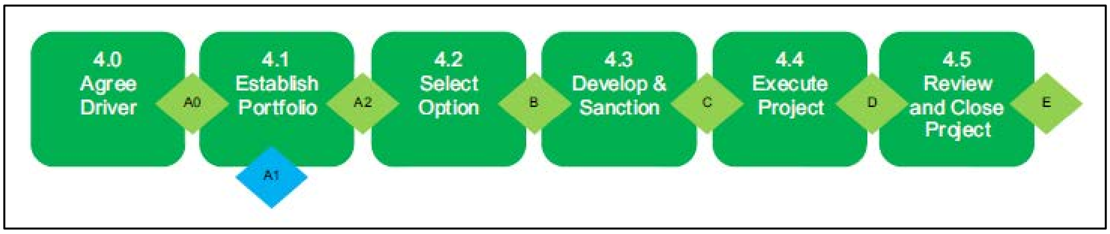


Figure 4: Network Development Process

A gate keeper is assigned to each of the gates with accountability for determining whether sufficient development has been undertaken (by reference to an agreed check-list) and whether the time is right to move to the next process stage (which is informed by the underlying driver of the investment and the timescales of future development).

Typically, projects progress linearly from one stage to the next. However, there are instances, particularly for customer-driven investments, where projects may go forward or backwards one or more stages. For instance, a customer that terminates their project may move from Stage 4.2 to Stage 4.5 so that the investment can be closed; or a customer may change its connection requirements during Stage 4.3 (via a new application) such that it might be appropriate to return to Stage 4.2 to review the option selection.

Stage 4.0 – Confirm and Agree Driver

This stage records the driver for an investment and the outputs that are expected to be delivered. Typical drivers include connecting a new customer, removing constraints on system boundaries, or maintaining compliance with industry codes and standards. Once a driver has been established, the investment will proceed to Stage 4.1.

Stage 4.1 – Establish the portfolio by creating an initial plan entry

The aim of this stage is to establish and maintain a portfolio of all potential investments required to meet our customers' needs and identify high-level investment costs and development milestones. This is the first building block from which investment scenarios can be created for business planning purposes. This phase of work will be undertaken with input from a cross functional scheme team that encompasses the wide range of engineering and commercial disciplines required to develop the project.

At the end of this stage an initial project scope will have been outlined and costed (this will include lead assets and the typical non-lead assets that are associated with this, considering the likely investment context e.g. if an existing substation is being extended or if a new site is required); initial resource estimates made; and a series of future milestones identified to ensure that subsequent development and construction activities meet the customer's requirements. Options and issues for consideration in future stages of development may also be identified and recorded.

All investment costs at this stage are based on a Cost Book and expenditure phased using pre-defined spend profiles. The Cost Book provides a list of standard transmission assets and development activities, and the average unit cost to procure and / or install these. The costs provided by the Cost Book are based on delivered and tender returns and it is updated annually. The phasing considers factors such as the likely complexity of the work (e.g. if a development consent order will be required) and the type of assets being installed (e.g. a transformer or overhead line).

When the milestones indicate that it is necessary to begin more detailed development (which, for connection offers is when the customer signs their contract), the project is presented to Gate A2 and, if successful, moved into Stage 4.2.

Stage 4.2 – Option Selection

The purpose of this stage is to identify a full range of options that satisfy the driver (whist complying with industry codes and standards) and to select a preferred option by identifying with more certainty the scope, programme, costs and issues associated each of these potential options. This work is usually in the form of obtaining existing records and site information, and then undertaking desktop assessments. The stage will identify 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; choices such as on-line versus off-line build and air-insulated versus gas-insulated solutions; and the application of any lessons learnt from similar previous projects. During this stage we will also considered the availability of whole system options, if that has not already been assessed through another process, which are covered below.

The options are then assessed to identify a preferred option. Options are costed using the Cost Book. When decisions are finely balanced, a more detailed cost benefit analysis (CBA) is undertaken. Option selection considers our anticipated investment costs as well as non-economic issues such as impact on the environment (e.g. noise impacts) and the challenges gaining the necessary consents.

Once a preferred option is selected and it is right to commit resource to develop and sanction the selected option, the project is presented to Gate B and, if successful, moves into Stage 4.3.

Stage 4.3 – Develop and Sanction

During stage 4.3 further work is undertaken to develop the preferred option to the level of accuracy required to achieve financial sanction and move into the tender and delivery stage. Survey works (e.g. noise assessments and asbestos surveys) and further detailed design work (e.g. engineering drawing production) is undertaken to establish a comprehensive project scope, identify and address hazards, and ensure resources are in place to deliver the project (including system access).

At the end of this stage, the design will be costed using a bottom-up assessment and a full quantitative risk assessment (QRA) undertaken. The level of detail and accuracy determined by the stage is sufficient for National Grid to undertake a rigorous assessment of tender returns and subsequently 'baseline' the investment to monitor progress during the delivery stage.

Once this stage is completed the investment is then taken forward for full financial sanction approval by the relevant investment committee. Provided the driver is still firm (e.g. customer commitments are being fulfilled), it will then be presented to Gate C and if successful move into Stage 4.4.

Stage 4.4 – Execute Project

This stage encompasses the delivery activities ranging from tendering and contract award through to physical construction work and commissioning. Throughout this stage our contractors are monitored to ensure the projects are delivered according to the agreed scope and cost.

Once the construction activities are completed, all financial matters settled (e.g. contract claims closed), lesson learnt captured and consolidated, and systems updated (for example, to ensure the correct maintenance occurs in the future), the investment is 'closed' by the relevant sanctioning authority and presented at Gate D. If successful, the project is moved into Stage 4.5.

Stage 4.5 – Review and Close Project

The purpose of this stage is to provide final confirmation that the investment elements have been closed in all business systems, and that all reported costs are final and complete. Once this assurance has been received, the investment process is complete.

This stage, in conjunction with the investment sanctioning committee, will also identify projects that should be subject to a Post-Investment Appraisal (PIA). A PIA is used for challenging investments to review decisions and ensure that appropriate lessons are learnt.

Our proposed Tier 3 investments had progressed to Stage 4.2 prior to the decision being taken to pause delivery of these schemes to allow the ENA *High Voltage Case Study* to carry out a full whole system assessment.

The cost estimates developed for these projects are shown in Table 4 below:

Proposed Tier 3 Investment Location	Scope	Cost (£m)
[redacted]		
		30.7

Table 4 – Summary of baseline investments proposals

1.6 Efficient Costs and Scope

As described in the preceding section, the NDP uses a Cost Book during the early development (Stages 4.0 to 4.2) to determine the investment costs (i.e. for each asset, the calculation is: number of assets required x unit cost of asset). The unit cost of key assets in the Cost Book has been recently benchmarked by external consultants. In more than half of the assets assessed, the consultants found the unit cost was below the industry average. In cases where the unit cost was between the industry average and maximum, we have included efficiency savings in the plan, to align our unit costs with the industry average. The review found no assets had unit costs above the industry maximum. Details of the study and the methodology used can be found in Chapter 14 and in NGET_A14.02 TNEI Asset Unit Cost Methodology Review Annex.

In addition to ensuring the unit costs are efficient, we also ensure the designed scope of the schemes are efficient. This takes places in a series of design reviews. For customer connections, these typically occur once during the offer stage (Stage 4.0 / 4.1); and again, during development and sanction stage (Stage 4.3). Design reviews are intended to examine the safety, cost and environmental impacts of our projects throughout their entire lifecycle from design and construction through to operations, maintenance and final decommissioning. At these reviews, independent and experienced engineers challenge the engineering design decisions that have been made by the project teams, to ensure that minimum scope has been included. For some investment types, a checklist might be used to test whether lean design decisions that have been made in the past can be applied to similar investments being reviewed.

6. Stakeholder Engagement

As well as our formal involvement in the ENA Open Networks project, and specifically the *High Voltage Case Study,* we have also sought to engage directly with the ESO and DNOs as part of our T2 process.

The ESO has expressed strong agreement with our conclusion that there will be an ongoing need for reactive power compensation solutions to retain system voltages within SQSS limits.

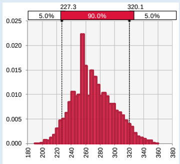
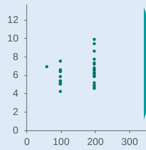
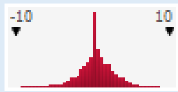
DNOs were keen to ensure that our plan facilitated future whole system ways of working and were supportive of our proposal for a low baseline position that would allow further investments to be identified through collaborative working.

Our approach is in line with our aim to create a business plan submission that facilitates whole system planning and processes to assess all whole system options that may be available and identify the most economic for the consumer.

7. Managing Uncertainty

The ESO and RIIO-2 Challenge Group have indicated they are keen to ensure we can deliver a transmission solution to future system operability issues, where this is deemed best for consumers through a whole system process. To facilitate this, we propose a new volume driven uncertainty mechanism, based on a unit cost allowance(s) that would automatically adjust our baseline allowance (up or down). This protects consumers from uncertainty whilst ensuring we can play our role in facilitating the operation of a zero-carbon system by 2025. This UM would cover transmission reactor investments as well as other types of reactive compensation investments that may be required to manage other system operability issues.

Our proposal for a new system operability mechanism is summarised in the table below.

System Operability (Voltage) – Unit Cost Allowance (UCA)		
Uncertainty characteristics	**T1 experience and learning**	**T2 proposals**
i) Risk and ownership • System need and best whole system solution uncertain • Requirements driven by expanded annual ESO NOA process and System Operability Framework • Network company manages cost risk, whilst consumer best to manage volume risk **ii) Materiality** • Volume uncertainty due to supply & demand changes is £92.9m *(90% of Monte Carlo with total cost between £227m and £320m)*  **T2 CAPEX probability distribution** (output of Monte Carlo analysis) • Additional whole system uncertainty down to £30.7m baseline = *£290m uncertainty range* **iii) Frequency and probability** • Possibly annually, at least biennial • 100% probability of some change in future requirements	**i) T1 experience** • Requirement to deliver both static & dynamic reactive compensation on the system increasing as more distributed and renewable generation connect - Increasing system voltage and negative reactive power demand - Reducing inertia and short circuit level • T1 funding through a fixed ex-ante allowance not subject to UCA • Significant uncertainty around volume and location of reactors and STATCOMS • Approach to whole system assessment under development **ii) Learnings for T2** • Need for reactive equipment will be determined by ESO expanded NOA or DNO whole system collaboration • New UCA required to adjust allowances and allow work to commence when transmission solution chosen	**i) Proposed mechanism and benefits** • Need triggered either when ESO has provided delivery signal or whole system process with DNOs has completed • Static - ordinary least squares regression and average unit costs modelled for (i) all schemes, (ii) by voltage and (iii) by size • Dynamic – average unit costs modelled for all projects due to input data sample size • Preferred model for static based on average unit cost by size & dynamic based on average unit cost for all projects **Inputs (£m vs. MVar)**  **Proposed Design** Static capability 60MVAr: [redacted] £m/MVAr 100MVAr: [redacted] £m/MVAr 200MVAr: [redacted] £m/MVAr Dynamic capability All MVAr: [redacted] £m/MVAr **Testing (cost vs. allowance)**  Mean: £0.6m Std. Dev.: £1.9m • Revenue calculated based on latest 5 year RRP forecast of outputs in order to minimise customer charging volatility **ii) Drawbacks and mitigations** • UCA restricted to set unit sizes may restrict type of solution • All system operability solutions are market tested by the ESO, or compared through the expanded NOA process, which mitigates any reduction in scope for innovation

Full details of our proposed uncertainty mechanism are detailed in NGET_ET.12 Uncertainty Mechanism Annex.