Investment Decision Pack

NGET A7.02 Incremental Wider Works

December 2019

As a part of the NGET Draft Business Plan Submission

nationalgrid

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Justification Paper Load Related – Incremental Wider Works (Boundary Capability)			
Primary Investment Driver	Reduction of ESO system constraint costs Cost benefit case assessed through ESO Network Options Assessment (NOA)		
Reference	NGET_A7.02 Incremental Wider Works		
Location in main submission narrative	Chapter 7 – *Enable the ongoing transition to the energy system of the future* Section 5.1 i) – *Innovate and invest in network reinforcement to facilitate a changing market and keep costs down*		
Cost	£507m		
Delivery Year(s)	2021 – 2026		
Reporting Table	B Series tables and totex cost-matrix tables		
Outputs for RIIO T2	22.5GW of Boundary Capability		
Spend Apportionment	**T1**	**T2**	**T3**
	£122m	NOA projects: £492m	£348m
		VIP Anticipatory Investment: £15m	
Total:		**£507m**	

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

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Executive Summary

Incremental Wider Works provide transfer capability between different areas of the transmission system. This allows power to move around the network freely, providing consumers continual access to the lowest cost sources of power and protecting them from unnecessary operating costs, as well as ensuring the usage of low carbon generation sources can be maximised.

We work in close collaboration with the Electricity System Operator (ESO) to provide inputs to their independent annual Network Options Assessment (NOA). The NOA process uses Future Energy Scenarios (FES) to forecast future system boundary capability requirements. We, as a Transmission Owner (TO), submit reinforcement investment options to the ESO that can provide the additional future boundary capability required. The ESO then carries out regrets-based cost benefit analysis to determine which investment options provide value for consumers and when these should be delivered.

We have used the output of the 2018/19 NOA process (the most recent available) and our analysis of the Common Energy Scenario to determine our T2 business plan.

We submitted 107 options to the ESO for analysis in the 2018/19 NOA, of these options 99 were assessed by the ESO. This range of options included increasing the capacity of existing circuits, installing reactive compensation to improve voltage performance, using power flow control devices and quadrature boosters to optimise power flows across the various circuits that make up a boundary, and building new transmission circuit routes.

Through assessing the NOA results and direct engagement with the ESO, 27 of these options were identified as requiring either delivery or the commencement of spending in the T2 period.

Where the NOA process made a clear recommendation as to the delivery date for an investment option, this was reflected in our business plan. Where uncertainty over optimal timing exists, we used our analysis of the Common Energy Scenario to determine delivery dates.

Total investment of **£507m** in the T2 period is included in our baseline plan for delivery and development of incremental wider works projects that provide boundary capability of 22.5GW. Post-consenting costs for projects that meet the expected criteria for Large Onshore Transmission Investments (LOTI) and Competitively Appointed Transmission Owner (CATO) have not been in included in our plan. In order to facilitate competition, we are proposing pre-consents expenditure to progress projects with a NOA proceed signal that also meet Late CATO. Further detail in Annex *NGET_A7.06 Facilitate competition (pre-consents)*.

Based on the ESO's independent cost benefit analysis (2018/19 NOA), these investments will deliver savings for the consumer, in the form of the present value of reduced system constraint costs over 40 years, in the range of £21bn to £121bn across the different FES scenarios. This roughly translates to a minimum annual constraint cost saving of £525m/annum (we have more than halved this for our main business plan narrative, to £250m/annum, to provide a conservative estimate).

We have developed a robust unit cost allowance to manage boundary capacity volume uncertainty in the T2 period. This mechanism will automatically adjust allowances up and down depending on customer requirements.

1. Introduction

Transmission System Boundaries

The transmission system is designed to ensure that there is sufficient capability to transport power between areas where power is generated to where it is used.

To facilitate the analysis of network capability requirements, we have worked collaboratively with the Electricity System Operator (ESO) to create notional system boundaries across the transmission system. Boundaries divide the system into sections and are used to assess whether forecast future power flows can be accommodated between the different areas of the network. The existing boundaries are shown in Figure 1.

[redacted]

Figure 1 – Transmission System Boundaries

Boundary Capability and Constraint Management

The National Electricity Transmission System Security and Quality of Supply Standard (referred to for the rest of this Justification Report as the SQSS) defines a methodology for calculating the required capability for a system boundary based on the levels of generation and demand on either side of that boundary. The capability of a boundary is calculated under the worst-case credible fault conditions for that boundary (as defined by the SQSS). This approach ensures that there is sufficient network capability to continue transporting power securely around the country and allow the ESO to operate the network, even under credible worst case conditions.

When there is insufficient capability on a system boundary to accommodate the forecast power flows (this is examined on a half hourly basis by the ESO) it is necessary for the ESO to restrict the level of power being transferred to remove the risk of any network overloads occurring in the event of an unplanned outage. These boundary restrictions are referred to as ‘constraints’.

The ESO manages these constraints by paying selected generators or demand side response providers to change their output or demand levels for a limited period (i.e. during the period when boundary transfers are forecast to exceed the boundary capability). To maintain the balance between generation and demand across the system it is necessary to also pay generation or demand located on the other side of the boundary to alter their output during this period, e.g. a reduction in generation on one side of a boundary must be matched by an increase on the other side to maintain energy balance. The associated payments are referred to as constraint payments.

Constraint payments can represent an annual cost for the ESO in the range of hundreds of millions of pounds (~£680m for 2018/19 as stated in the ESO’s Monthly Balancing Services Summary March 2019[1]). The cost of managing a constraint varies from boundary to boundary and is determined by the magnitude of the restriction and type of generation (or demand) being constrained. Whilst a level of constraints is a normal aspect of operating an economic and efficient system, insufficient boundary capability can lead to an uneconomic level of constraint costs such that investment to raise network capability would reduce the overall cost to consumers.

Transmission System Wider Works

Transmission system reinforcement works that increase the capability of boundaries are referred to as ‘wider works’. They are driven by the cumulative effect of generation and demand patterns around a boundary and are unlikely to be linked directly to any one individual customer connection.

Wider works can involve increasing the capacity of existing circuits, installing reactive compensation to improve voltage performance, using power flow control devices to optimise the balance of power flows on the circuits that cross a boundary, or building new transmission circuit routes. The wide range of possible wider works types means that project costs can also vary significantly from <£550k to >£1bn.

As the delivery lead time of transmission reinforcement schemes can often be longer than that for generation developments, decisions about transmission reinforcements have to be taken when the future generation development remains uncertain. This leads to a number of risks, for example, there is a risk that we could commit to investments that become unnecessary as customers change or cancel their plans. In addition, while the SQSS defines the capability that should be available on each boundary, more detailed analysis is needed to determine whether it is in the best interests of consumers to actually invest to provide this capability, or even invest more to provide capability beyond the minimum.

It is possible that the cost of delivering capability may in fact be greater than the constraint costs that would be incurred if the boundary was not reinforced. In some cases, a system constraint may only occur for small periods of time each year and the investment solution to resolve the constraint may be very costly. In this situation, it may be more economic for the ESO to manage the issue via constraint payments than for us to invest in a boundary upgrade as the constraint approach would result in lower overall costs for the consumer. Investment is only justified when total avoided constraint costs would be higher than the cost of reinforcement; the total constraint costs are calculated over the lifetime of the proposed investment option.

The exception to this approach is when boundary reinforcement is required to meet the Security criteria of the SQSS (see section 2 for more details). Under this condition reinforcement is required to provide network security and no cost benefit assessment is undertaken. Investments triggered by this condition are rare and none were required in T1.

[1] https://www.nationalgrideso.com/balancing-data/system-balancing-reports

To address these issues, an annual process to assess the need case for wider works, identify the transmission investment options available, compare the cost benefit delivered by investments vs constraint payments, and assess investment timing was developed by National Grid TO/SO (pre-legal separation). This is referred to as the Network Development Policy (NDP). This process balances the cost of investment against the cost of potential system constraints in order to determine the solution that minimises consumers' exposure to inefficient spending.

Over the T1 period the NDP methodology was used as the basis for the ESO's annual NOA process that now assesses the cost benefit case for all transmission wider works across GB.

Experience in RIIO-T1

Our T1 baseline plan was based on the 2012 version of the Gone Green Future Energy Scenario (as agreed with Ofgem). Using this scenario, we forecast the network boundary capability required and the reinforcement works needed to deliver that capability.

As the T1 period progressed three major factors combined to alter the timing, scope, and cost of the transmission system wider works we have actually delivered. These were:

- Actual generation and demand development differing from the Gone Green scenario
- The development of innovative network solutions that allowed incremental capacity to be provided, deferring or removing the need for baseline investments.
- The continued evolution of the annual cost benefit process used to assess the need case for wider works.

The actual generation and demand development that has taken place during T1 has meant that the power flows (and hence boundary capability requirements) forecast in the Gone Green scenario did not materialise.

The implementation of the annual assessment process allowed us to refine and optimise our wider works investment plan in response to these changes.

While some requirements and investments remained consistent, many were subject to change. In some cases, customers' investments were delayed, (e.g. generation projects connected later than forecast) meaning the associated boundary upgrade was also delayed. In other cases, the effect of differing generation and demand development was more extreme and resulted in the planned wider works investments being revised (scope and cost), cancelled completely, or new investment options being developed.

The combination of the changing system requirements and the evolving annual process resulted in significant changes to our wider works investment plan.

The T1 deal included an uncertainty mechanism (UM) designed to respond to changes in wider works volumes and protect networks and consumers and from forecast errors.

A comparison of our T1 baseline vs actual allowance and outputs for incremental wider works is shown in the table below:

	T1 Baseline	Actual (RRP 2018)
Outputs – Additional Boundary Capability	23.1 GW	12.4 GW
Allowance*	£2701m	£1387m

*baseline wider works and incremental wider works

Table 1 – T1 Baseline Vs Allowance

2. Network Options Assessment Process

During the T1 period the ESO developed a formalised annual assessment called the Network Options Assessment (NOA) process which covers all areas of the GB transmission system. This process was based on the methodology developed as part of the NDP. Following the legal separation of National Grid TO and SO, elements the NOA process are now owned and administered by the ESO with inputs provided from the incumbent TOs. This process recommends which wider works should be progressed and the optimal delivery date for these reinforcements.

The ESO's annual end to end NOA process can be split into distinct stages. The development of the Future Energy Scenarios (FES), the publication of the Electricity Ten Year Statement (ETYS), the submission of reinforcement options from Transmission Owners to the ESO, and finally the cost benefit analysis and publication of the NOA report.

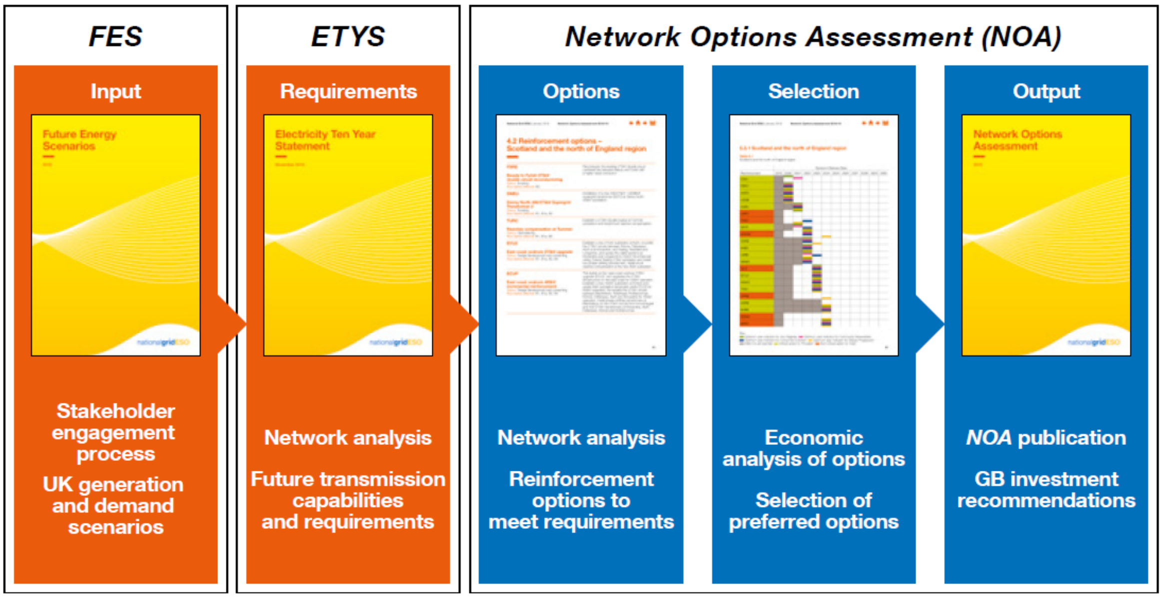


Figure 2 – End to End NOA Process

The FES includes a set of four scenario data sets that offer different credible views of electricity system usage over the next 30-years. Each individual scenario makes different assumptions regarding generation and demand growth, technology development, and electricity consumer behaviour.

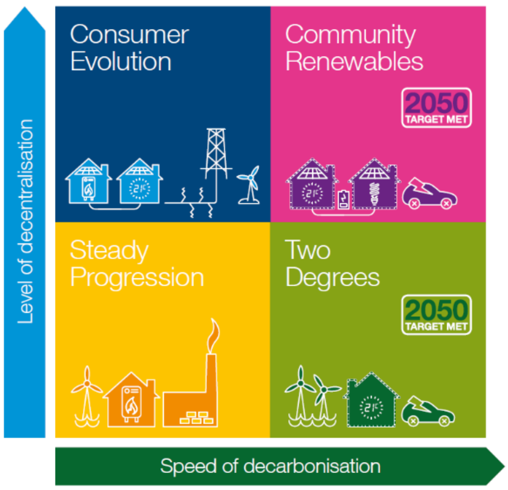


Figure 3 – 2018 Future Energy Scenarios

The FES acts as the basis for the overall NOA process and it is against these scenarios that future network needs are identified and assessed.

The ESO develops the FES independently but consults extensively across the full range of energy stakeholders, including NGET. The ESO describes the FES as follows:

"We produce our Future Energy Scenarios (FES) each year to identify a range of credible scenarios for the next 30 years and beyond. These consider how much energy we might need and where it could come from."

The next step in the process is the ETYS. This report uses the FES to forecast future transmission system boundary capability requirements under each scenario.

The ESO calculates these requirements by applying the methodology specified in the SQSS to the generation and demand assumptions made in each individual scenario.

The SQSS specifies two operating conditions under which boundary capability must be assessed: Economy; and Security. The Economy methodology assesses capability under 'normal' day to day operating conditions, i.e. the network operating with a range of different generation types (i.e. a representative mix of wind, interconnector, gas etc.) and a credible level of demand. The Security methodology assesses the network's ability to accommodate power flows under conditions when only 'traditional' thermal generation (e.g. gas, nuclear, coal) is available. The boundary capability required under each condition is referred to as the Required Transfer (RT). In general, the Economy RT is higher than the Security RT and hence is more likely to drive the need for system reinforcement.

The graphs below show the ETYS output for the B6 system boundary. Under all four scenarios the Economy RT exceeds the boundary's existing capability. This indicates a need for the boundary to be reinforced. However, the magnitude of additional capability and the timing it is needed differs across the four scenarios.

The shaded areas on each chart represent the distribution of annual power flow. The darker shaded area shows an area in which 50% of the annual power flows lie. In percentile terms, 75% of annual power flows are lower than the upper edge of the darker shaded area and 75% are higher than the lower edge. The lighter and darker shaded areas together show an area in which 90% of the annual power flows lie. In percentile terms, 95% of annual power flows are lower than the upper edge of the lighter shaded area and 95% are higher than the lower edge.

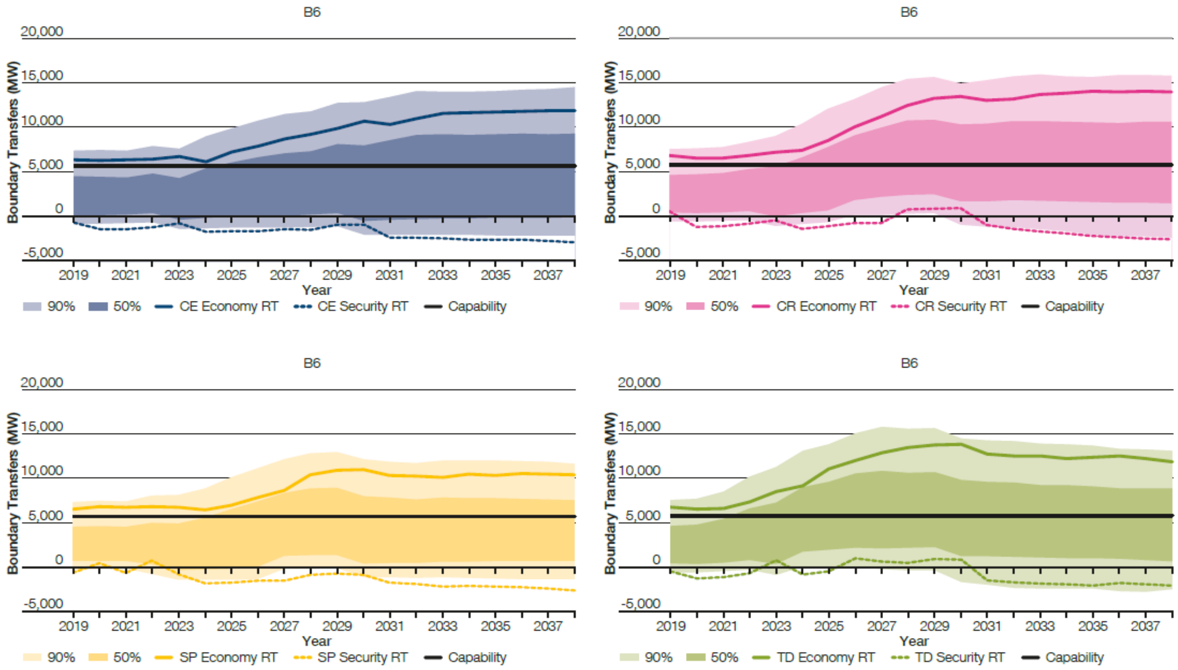


Figure 4 – ETYS Required Transfer Charts

The ESO describes the ETYS as follows:

The Electricity Ten Year Statement (ETYS) presents the National Grid Electricity System Operator's (ESO) view of future transmission requirements and the capability of Great Britain's (GB) National Electricity Transmission System (NETS). This is a significant part of our annual network planning process. Through it, we identify requirements that may lead to network development, which are then assessed through the Network Options Assessment (NOA) process.

Following publication of the ETYS the Transmission Owners (TOs) will submit reinforcement options to the ESO to address the needs identified in the ETYS report. As a TO we carry out power system analysis studies to identify which specific circuits (or other network parameters such as voltage performance) act as the limiting factor on each boundary and hence determine what specific investment options are available to provide additional capability for each system boundary.

To allow the ESO to carry out their whole system cost benefit analysis we provide the key inputs of the additional capability delivered by our options, a cost estimate, and a delivery programme for each option.

Once the ESO has the inputs from the TOs they can carry out the cost benefit analysis that informs the NOA report.

The NOA makes recommendations for each reinforcement option assessed indicating where development (and hence spending) should start, continue, pause, or stop. These recommendations are made on a Least Worst Regrets basis where the recommended course of action is the one that exposes the consumer to the minimum level of potential cost risk, i.e. the recommended course of action may not be the 'best' under a single scenario but provides the lowest level of risk when all possible outcomes are considered together.

In the majority of cases, we apply the NOA recommendations directly to our investment plans for the following year. However, these recommendations are not binding and we are free to pursue an investment plan based on our own views of what is required to meet our licence obligations should we wish to. This approach is normally only taken in the most marginal cases where there is potential that the recommendation may change in the following year and we believe that more efficient outcomes can be achieved through taking a different investment decision. For example, the development of a project may be recommended to proceed in the coming year. However, if we believe that there is a strong likelihood that the next years NOA will recommend that development be stopped we may choose to halt development a year early, contrary to the current NOA recommendation, and "save" the consumer a year of development costs.

The following sections explain how we have used the output of the 2018 NOA process (the 2019 version is not scheduled for publication until Jan 2020) to inform our baseline business plan proposals.

3. ESO NOA Cost Benefit Analysis Methodology and Results

Methodology

The methodology used for the ESO's NOA process is subject to industry consultation and is approved by Ofgem annually ahead of implementation for that year.

In summary, the NOA economic analysis involves forecasting the constraint costs that would be incurred across the different FES scenarios if no network upgrades are delivered and then comparing the cost and benefit of the investment options submitted by the TOs (i.e. cost of investment vs reduction in constraint costs).

The recommended timing of options is determined by assessing the 'optimal timing' for each reinforcement. This compares the delivery date that would maximise consumer benefit (i.e. constraint savings) across each of the individual scenarios.

The earliest possible date by which a reinforcement can be delivered is referred to as the Earliest In Service Date (EISD) and is supplied by the TOs.

If a reinforcement option has optimal delivery dates that are later than the EISD then there is no need for us to take immediate action to deliver that reinforcement, i.e. we can wait and only commence the investment when necessary.

Where the optimal delivery date is the same as the EISD across all four scenarios then it is clear that the reinforcement is required and delivery should proceed.

However, if the optimal delivery date aligns with the EISD in only some of the scenarios (i.e. the other scenarios indicate a later delivery date is optimal) then further analysis must be undertaken to determine if the investment should proceed or if it can be delayed. This is referred to as 'single year least worst regret analysis'.

For each scenario, this approach compares the cost of delivering an investment early (i.e. the cost of financing the investment) against the potential constraint costs that would be incurred if the investment was delayed.

The investment strategy that has the lowest downside risk (the Least Worst Regret) across the four scenarios is preferred as this minimises consumer exposure to costs.

Full details of the NOA methodology can be found on the ESO website.

Results

The NOA makes one of the following recommendations for each reinforcement option assessed.

- **Proceed**: The option is required by its EISD and work should start or continue to deliver by that date
- **Delay**: The optimal date for this option has been shown to match the EISD in at least one scenario. However, the single year regret analysis has shown that risk for consumers is minimised by delaying by one year to allow reassessment in the following years' NOA
- **Hold**: The option is required but is not needed, under any scenarios by the EISD. The investment decision should be put on hold
- **Stop**: The option is no longer required and should not be continued
- **Do not start**: The option is not required. Delivery should not begin.

Proceed, Delay, and Hold are hereafter referred to as Positive Recommendations and the associated reinforcements are on the 'critical path' of required investments that deliver an economic benefit to consumers. A Proceed recommendation means that spending is required in the following year to maintain the ability to deliver by the EISD.

Stop and Do Not Start are hereafter referred to as Negative Recommendations.

4. Our Inputs to the 2018 NOA Process

Once we have identified the 'limiting factor' of a system boundary we will develop a range of options to address this limitation and increase the boundary capability to the point where compliance with the requirements of the NETS SQSS is restored across the forecast period (the resulting boundary capability may exceed the SQSS compliance level due to the 'step change' nature of capability delivered by transmission system reinforcements).

We consider and assess a range of different options for providing additional boundary capability including: enhancement of our existing assets, innovative use of new technologies, whole system options, and construction of new transmission assets. Market based solutions to boundary constraints are identified and assessed by the ESO. We are not privy to the commercially confidential market cost information that would be required to allow us to engage directly with customer to assess any services they may be able to offer as an alternative to a transmission system investment.

Providing a Range of Options

When developing the options to provide to the ESO, we include more than one feasible reinforcement option for a boundary. In some cases, these may be direct alternatives and in others they may be sequential reinforcements that allow the total additional capability needed across a boundary to be delivered over time, reducing risk for the consumer by allowing capability to be delivered only when need cases become more certain, and reducing financing costs by deferring investment where possible.

While all the options we develop are unique, there can be cases where they provide identical benefits. If two projects deliver the same level of additional capability, can be delivered by the same date, and offer no other qualitative benefits (e.g. environmental impact), then the cheapest option clearly offers the best value for consumers and only this would be put forward into the NOA process. However, where options offer different levels of capability or delivery timescales, both would be submitted to the NOA process to test the cost benefit delivered by each. This ensures a diverse range of options are submitted each year.

An example of this can be seen in our input to the 2018 NOA. Boundary B7 was identified as requiring additional capability.

We submitted 22 options to the ESO that would provide additional capability across the B7 boundary. These options ranged from non-build investments (hotwiring – modifying existing circuits to operate at higher ratings), upgrading existing assets (replacing conductor systems), to the delivery of new transmission routes. Costs ranged from ~£200k to ~£1.6bn. Delivery dates also ranged from options that could be delivered in the following year to longer term projects with >10-year lead times.

This optionality also exists on a project by project basis. For example, as part of our analysis of B7 investment options the Norton – Osbaldwick double circuit route was identified as a limiting factor for that B7 boundary. We submitted three variations of a conductor upgrade project for these circuits to the ESO:

Option	Description	EISD*	Cost (£m)
Reconductor [redacted] km Norton-Osbaldwick 400kV circuit single circuit A347	Reconductor a limited section of one of the circuits	2021	[redacted]
Reconductor [redacted] km of Norton-Osbaldwick 400kV double circuit A347 & A355	Reconductor a limited section of both circuits	2021	[redacted]
Reconductor the rest of the Norton-Osbaldwick 400kV double circuit A347 & A355	Reconductoring the remaining sections of the double circuit route	2022	[redacted]
*EISD = earliest in service date			

Table 2 – Example of NOA Optionality

Providing a range of options, at both a portfolio level and also on a project by project basis, gives the ESO maximum flexibility to identify the overall sequential reinforcement strategy that can provide maximum benefit for the consumer given the level of uncertainty around future requirements.

Using Innovative Technologies

During RIIO-T1 we have sought to proactively drive the development of new technologies that can be used to provide system boundary upgrades. In doing this we can ensure we remain at the forefront of transmission system technology and deliver increased value for consumers through identifying lower cost solutions.

A prime example of this commitment is the development of Smartwires projects that allow us to control system power flow directions. These devices can be more effective and flexible (both in terms of performance and installation requirements) than the traditional assets used to achieve this power flow control – Quad Booster

Transformers[2]. Smartwires offer an alternative to upgrading existing conductor systems. These solutions can offer capability at a lower cost than circuit reconductoring or building new transmission routes and result in less local impact compared with having to carry out upgrade work on overhead line routes that can extend many 10s of kilometres. In addition, they can be delivered in shorter timescales than traditional upgrades allowing investment decisions to be made closer to the time of need, reducing the risk of inefficient investment.

We worked directly with the owner of this technology to develop world first transmission system solutions and allow us to provide these options as inputs to the ESO's NOA process with confidence that the cost and capability increase forecast are accurate and deliverable.

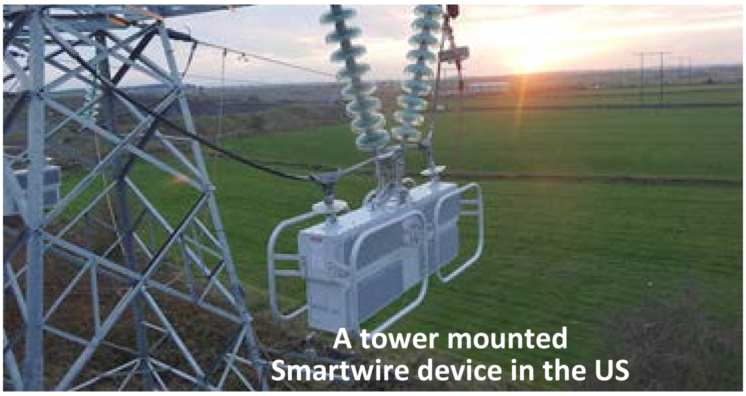


Figure 5 – Smartwire Device Installed on Overhead Line

The development of Smartwires has so far allowed 3 'traditional' transmission investment schemes to be replaced or deferred resulting in a forecast capital cost saving of over £300M over the T1 period.

Of the 10 Smartwires options that were assessed as part of the 2018/19 NOA. 3 projects were recommended to proceed delivery in the T1 period, and a further 3 being recommended for delivery in T2.

We are continuing to work with the ESO to maximise the benefits that can be offered by Smartwires and will continue to submit Smartwire options (where appropriate) into future iterations of the NOA process.

Our baseline investment plan for the T2 period includes 3 Smartwires schemes. The costs associated with these schemes have been included in our analysis of uncertainty mechanisms to support Incremental Wider Works investment in T2 to ensure that the value identified through the development in T1 is built into our T2 proposals (see Chapter 7, Section 7 of the main narrative or our ET.12 Uncertainty Mechanism Annex for more details).

Developing Costs and Delivery Programmes

Each option we submit to the ESO has a cost estimate and delivery programme (including a spend profile). This information is a key input to the NOA's cost benefit process.

All investment development carried out by NGET is done in line with our Network Development Process (NDP[3]), this framework provides a consistent approach to project development and a rigorous governance framework.

The process, applied to all investment types, is characterised by stages of activity (boxes) and governance gates (diamonds), as shown below. Investment options developed for submission to the NOA process are subject to phases 4.0 and 4.1 of this process. When an investment option receives a Proceed recommendation it will progress through the rest of the NDP stages.

[2] Depending on the specific network requirements being addressed there may be some instances where Quad Boosters can provide greater capacity than Smartwires and hence QBs may still form part of future NGET investment plans.

[3] Please note that the Network Development Process is entirely separate from the Network Development Policy described in Section 1.

An option that is 'Proceeding' is still submitted annually to the NOA process in order to continually test the need case and examine if any changes in costs (as the project becomes more developed) would alter the NOA's recommendation.

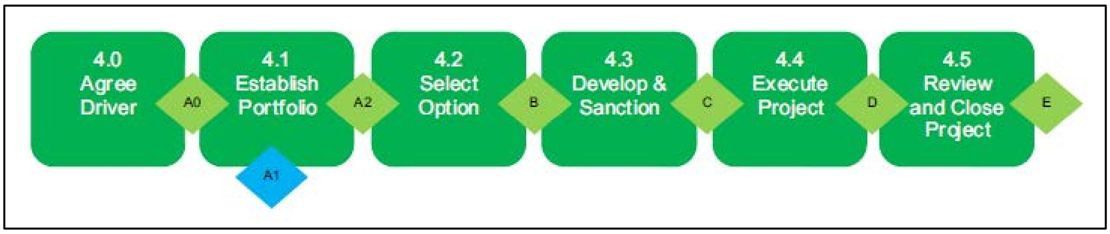


Figure 6 –Stage Gates of NDP Process

Stage 4.0 – Confirm and Agree Driver

This stage records the driver for an investment, in the case of wider works this will be the requirements set out by the ESO in the ETYS. Once a driver has been established, the investment will proceed to Stage 4.1.

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

The aim of this stage is to develop an initial view of investment costs and development milestones. This phase of work will be undertaken with input from a cross-functional scheme team that encompasses the 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 determine a feasible delivery date.

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 asset 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).

The unit cost assumptions for key assets in the Cost Book have 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. 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 Our total costs and how we provide value for money* and Annex *NGET_A14.02 TNEI Asset Unit Cost Methodology Review*.

Once a project is recommended to Proceed in the NOA results it will be formally created in our NDP, progressing to Stage 4.2.

Cost Certainty

The closer a project is to delivery, the further through the NDP it will have advanced. For example, a scheme in delivery will have advanced to Stage 4.4 where a thorough review of design options will have taken place and a final design agreed. At this stage there will be a very high certainty of cost.

Projects at an earlier stage of development (it is important to note that it is not efficient to commence detailed development of a project until necessary in case there is a change in the need case) will have an initial design agreed and forecast costs. As such there is greater level of cost uncertainty associated with projects at the early stages of development. The NOA will continue to evaluate the cost benefit of the investment each year of the projects development and delivery, to ensure that it remains in consumers' interest to progress the investment.

However, it should be noted that the majority of the projects included in our baseline plan (described in Section 5) consist of types of work that we have delivered on many occasions in the past (e.g. hotwiring, re-conductoring, installation of reactive compensation) and therefore we have a high confidence in our ability to forecast these costs. Our Cost Book uses historical schemes to determine unit costs and there is large number of historical schemes of these types on which to base this analysis.

Larger projects that have longer delivery lead times and may require consenting activities inherently have the greatest level of cost uncertainty. However, as described in Section 9, we have excluded from our baseline any projects that meet the expected criteria for early (>£50m with scope for innovation) or late competition (>£100m, new, and separable). The LOTI / CATO process allows for the need and cost of these projects to be reviewed much closer to delivery once any cost uncertainty has been reduced.

Identifying Whole System Options

While the ESO takes the lead in identifying commercial options that may be provided by existing customers to manage system constraints, we have still been proactive in investigating other potential whole system alternatives to our investment options to ensure we provide the best inputs to the NOA process and can develop the most robust and certain baseline plan for the T2 period.

DNO Alternatives

We engaged extensively with Distribution Network Owners (DNOs) across various elements of our T2 plans and specifically discussed with them the need case and scope of the wider works we proposed to include in our baseline plan. We sought feedback from the DNOs regarding the process we had followed and whether they may be able to offer alternatives to our proposed investments (either through investment on their network or through DSO actions with flexibility alternatives; see below).

While all DNOs expressed interest in participating in the ESOs expanded NOA process in the future, no alternatives to the baseline investments we proposed were put forward. The ability to economically provide the power transfer capability required by the ESO at distribution voltages was discussed as one of the challenges by some networks[4].

Flexibility Alternatives

The decentralisation and digitalisation of energy is leading to new opportunities to resolve network issues using storage technology (e.g. batteries) and demand side response (where electricity consumption is shifted as a service to the network operator). DNOs have started procuring flexibility to resolve issues on their networks and the ESO also procures flexibility services through ancillary services contracts and the Balancing Mechanism. To date, the focus has been on ancillary services and short-term Balancing Mechanism actions, rather than on providing a longer-term network capability type service.

At transmission level, it is primarily the role of the ESO to establish markets and procure services. The NOA process is expanding and evolving through the Network Development Roadmap to include the assessment of non-network solutions and the ESO is proposing to enhance its ability to enter into long-term contracts with flexibility providers in the T2 period.

As a Transmission Owner, we are keen to understand the role we can play in helping to bring these technologies to market for the benefit of consumers. During RIIO-T1 we have worked with developers, particularly energy storage specialists, to understand what opportunities may exist to increase boundary capability using contracted commercial services from our customers alongside non-build solutions such as offering short-term overload capability of our assets to the ESO.

This work was successful in developing new options to increase boundary transfer capabilities. Our work, with partner developers, demonstrated a cost benefit case for this approach that could benefit consumers.

[4] High voltage transmission circuits naturally have much greater capacity than lower voltage distribution circuits. Approximately ten 132kV distribution circuits are required to provide the equivalent capacity of a single 400kV transmission circuit.

However, engagement with the ESO and Ofgem resulted in a decision that these options should be progressed through a commercial market rather than through direct partnership between us and our customers. Therefore, these options were not ultimately submitted into the NOA process.

Our T2 engagement sought to better understand and align on the potential for flexibility against various network opportunities in the T2 period. From our experience in T1 and our T2 specific engagement, we understand that there are opportunities for flexibility to provide consumer value in delaying network investment at the interface between transmission and distribution. This has been part of our engagement with DNOs and is reflected in our plans at the transmission / distribution interface. In addition, there are opportunities to compliment network investment on the wider electricity transmission network, particularly as flexibility solutions can often be deployed faster than most traditional network reinforcements.

We understand that the opportunity for flexibility solutions to provide an enduring alternative to network reinforcement is currently limited due to scale and duration.

However, we are continuing to work with our customers, the ESO, and Ofgem to facilitate these options forming part of future boundary reinforcement options.

<u>Our Final Inputs to 2018/19 NOA Process</u>

A total of 99 individual NGET reinforcement options were assessed by the ESO as part of the 2018/19 NOA process.

These reinforcements were a mix of innovative new technologies, enhancement of existing assets, and new infrastructure.

The costs and delivery timescales for these options were developed using the methodology of our Network Development Process (TP500) in an identical manner to that applied to works for generation and demand customer connections. The end to end NDP process is described fully in the Demand and Generation Connection Justification Papers (*NGET_A8.03* and *NGET A8.02* respectively).

5. Building our Baseline Plan

<u>Identifying Projects for Inclusion in our Baseline Plan</u>

The results of the assessment of our 99 inputs to the 2018/19 NOA process are summarised below:

99 NGET INVESTMENT OPTIONS SUBMITTED FOR ECONOMIC ANALYSIS				
60 POSITIVE RECOMMENDATIONS			39 NEGATIVE RECOMMENDATIONS	
21 PROCEED	2 DELAY	37 HOLD	5 STOP	34 DO NOT START

Table 3 – Recommendations for NGET Investment Options

Projects that received positive recommendations and have optimal delivery dates that require spending in the T2 period to achieve, are included in our baseline plan.

However, to enable competition, any projects meeting the criteria for competition have been excluded from our baseline plan. Four projects were excluded under this approach, described in *Chapter 7, Section 5.2 Our proposal to facilitate competition and new business models to minimise cost* of the main business plan narrative and annex *NGET_A7.06 Facilitate Competition (pre-consents).* These projects were: (i) Peterhead to Drax HVDC – E4D3, (ii) Torness to Hawthorn Pit HVDC – E2DC, (iii) South London to South East Coast – SCN1, (iv) Central Yorkshire – OENO.

Applying these criteria and excluding those that are contestable, 25 projects reviewed under the 18/19 NOA were identified for inclusion in our baseline plan (13 Proceed, 1 Delay, and 11 Hold).

These projects are consistent with the requirements of the Common Energy Scenario (CES) as the generation and demand forecast in the CES falls within the range of the envelope defined by the four FES. Please see the detailed description in the section "*Delivery Dates for Projects in our Baseline Plan"* for more information on how our baseline plan accounts for the various potential scenario outcomes.

The 25 projects identified for inclusion in our baseline plan directly through the NOA process are shown in the table below.

NOA Ref.	Description	T1 Spend (£m)	T2 Spend (£m)	T3 Spend (£m)	Total Cost (£m)
BMM2	Two new 225MVAr switched capacitors (MSCs) at Burwell Main would provide voltage support to the East Anglia area as future system flows increase.	[redacted]	[redacted]	[redacted]	[redacted]
BMM3	One new 225MVAr switched capacitor (MSC) at Burwell Main would provide voltage support to the East Anglia area as future system flows increase.	[redacted]	[redacted]	[redacted]	[redacted]
BNRC	Provide additional reactive compensation equipment at Bolney and Ninfield substations to maintain voltages within acceptable operational limits in future network operating conditions.	[redacted]	[redacted]	[redacted]	[redacted]
BRRE	Replace the conductors in the parts of the existing Bramford to Braintree to Rayleigh overhead line that have not already been reconductored, with higher-rated conductors, to increase the circuit's thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
BTNO[5]	Construct a new 400kV double circuit between Bramford substation and Twinstead tee point to create double circuits between Bramford and Pelham and Bramford to Braintree to Rayleigh Main. It would increase power export capability from East Anglia into the rest of the transmission system.	[redacted]	[redacted]	[redacted]	[redacted]
CBEU	Establish enhanced thermal ratings on the Creyke Beck to Keadby 400kV route.	[redacted]	[redacted]	[redacted]	[redacted]
CDRE	Replace the conductors on the existing double circuit from Cellarhead to Drakelow with higher-rated conductors to increase their thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
FMHW	Thermal upgrade of the Feckenham to Minety single circuit to allow it to operate at higher temperatures, and increase its thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
HAE2	Replacing an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.	[redacted]	[redacted]	[redacted]	[redacted]
HAEU	Replacing an existing transformer at Harker substation with one of higher rating to prevent overloading following transmission system faults.	[redacted]	[redacted]	[redacted]	[redacted]
HWUP	Hackney, Tottenham and Waltham Cross substation and double circuite uprate from 275kV to 400kV. This will strengthen the power flow into London, via Rye House, down to Hackney.	[redacted]	[redacted]	[redacted]	[redacted]
IFHW	Thermal upgrade of the Feckenham to Ironbridge circuits to allow them to operate at higher temperatures, and increase their thermal ratings.	[redacted]	[redacted]	[redacted]	[redacted]
KLRE	The 400kV circuits running from Kemsley via Longfield Tee to Littlebrook would be reconductored with higher-rated conductors.	[redacted]	[redacted]	[redacted]	[redacted]
KWHW	Thermal upgrade of the Keadby to West Burton circuits to allow them to operate at higher temperatures, and increase their thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
MBRE	Replace the conductors in the Bramley to Melksham circuits with higher-rated conductors to increase their thermal ratings.	[redacted]	[redacted]	[redacted]	[redacted]
NEMS	Three new 225MVAr switched capacitors (MSCs) at Norton, Osbaldwick and Stella West 400kV substations would provide voltage support to the east side of the transmission network as future system flows increase.	[redacted]	[redacted]	[redacted]	[redacted]

[5] While this project is >£100m we do not believe that it meets the criteria of being new and separable and hence it is not excluded from our baseline along with the project described in Section 9.

NOR1	Replace some of the conductors in the Norton to Osbaldwick double circuit with higher-rated conductors to increase the circuits' thermal ratings.	[redacted]	[redacted]	[redacted]	[redacted]
RTRE	Replace the conductors on the remaining sections of the Rayleigh to Tilbury circuit, which have not recently been reconductored, with higher-rated conductors. These would increase the circuit's thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
SEEU	Provide a new communications system and other equipment to allow existing reactive equipment to be switched in or out of service very quickly following transmission system faults. This would allow better control of system voltages following faults.	[redacted]	[redacted]	[redacted]	[redacted]
SER1	Replace the conductors from Elstree to Sundon circuit 1 with higher-rated conductors to increase their thermal rating.	[redacted]	[redacted]	[redacted]	[redacted]
THRE	Replace the conductors in the Hinkley Point to Taunton circuits with higher-rated conductors to increase the circuits' thermal ratings.	[redacted]	[redacted]	[redacted]	[redacted]
THS1	Install series reactors at Thornton substation. These would connect the parts of the site at present being operated disconnected from one another to limit fault levels. The reactors would allow flow sharing between the different parts of the site and reduce thermal overloads on connected circuits.	[redacted]	[redacted]	[redacted]	[redacted]
WHTI	Turn-in the West Boldon to Hartlepool circuit, to connect to the Hawthorn Pit site it currently passes. This would create new West Boldon to Hawthorn Pit and Hawthorn Pit to Hartlepool circuits and ensure better load flow sharing and increased connectivity in the north east 275kV ring.	[redacted]	[redacted]	[redacted]	[redacted]
WYQB	Install a pair of quad boosters on the double circuits running from Wymondley to Pelham at the Wymondley 400kV substation. These would improve the capability to control the power flows on the North London circuits.	[redacted]	[redacted]	[redacted]	[redacted]
WYTI	Modify the existing circuit that runs from Pelham to Sundon with a turn-in at Wymondley to create two separate circuits that run from Pelham to Wymondley and from Wymondley to Sundon. This will improve the balance of flows.	[redacted]	[redacted]	[redacted]	[redacted]
		£108.3m	**£450.6m**	**£348.1m**	**£971.1m**

Table 4 – NGET Baseline IWW Investment Options Identified Through 2018/19 NOA

In general, all options that received negative recommendations were excluded from our business plan. However, as the NOA provides only investment recommendations we can take our own view as to the appropriateness of these recommendations. It is common practice for us to review recommendations with the ESO following publication of the final NOA report. Where we believe a different approach is justified we may choose not to directly follow the NOA recommendation.

Two projects that received Do Not Start recommendations in the 18/19 NOA were identified by us as requiring further review, referred to as: MHPC and HSS2. Both of these are power flow controller schemes that increase the capability of the B6 boundary.

MHPC will install power flow controllers on the circuits North of Harker that cross the B6 boundary. The scheme will increase the stability limit of the boundary. The stability limit for B6 is inconsistently calculated between NGET, SPT and ESO. This issue is recognised and is being addressed through the Joint Planning Committee (JPC). Based on discussions with ESO this lack of clarity was a significant factor in NOA's recommendation. The FES requirements in the T2 period for the 19/20 NOA process indicate B6 capability requirements that are much higher than any of the calculated stability limits, and it is therefore our view that a scheme to increase the limit will be required in T2. Based on comparisons of cost and deliverability of alternates such as synchronous compensators and series capacitors we believe that MHPC is the best option and have consequently included it in our baseline plan.

We submitted four options to NOA 18/19 for power controllers on the two circuits between Harker and Stella West that will increase the thermal capability of B6. These were FSPC and HSPC, which put a large controller on each of the circuits; HSS1, which put smaller controllers on the both circuits, and HSS2, which increases the capability of the HSS1 scheme to match that of FSPC plus HSPC. NOA recommended proceeding with FSPC and HSPC in the T1 period, increasing the B6 thermal capability beyond its current stability limit. On the basis of the ongoing discussions around the stability limit, we have proceeded with HSS1, which will be installed in 20/21, to increase the thermal capability of B6, and have included HSS2 in our T2 plan as a scheme that will further increase the thermal capability to that recommended in NOA once the stability limit has been raised. This approach is intended to ensure that we will not invest in raising the thermal limit before the benefit of the investment can be realised.

It was our belief that NOA recommendation was incorrect based on the incomplete stability modelling and analysis and that these projects represented better value for consumers than others recommended by the process and hence should be included in our investment plans. Through collaborative review with the ESO it was agreed that the recommendations for these schemes were indeed erroneous and that they should form part of the future optimal investment strategy. As these schemes required spending in the T2 period they have been included in our T2 baseline. These schemes are shown below:

NOA Ref.	Description	T1 Spend (£m)	T2 Spend (£m)	T3 Spend (£m)	Total Cost (£m)
HSS2	Install Smartwire device along Fourstones to Harker to Stella West 275kV route.	[redacted]	[redacted]	[redacted]	[redacted]
MHPC	Install Smartwire device along Harker to Gretna & Harker to Moffat 400kV route.	[redacted]	[redacted]	[redacted]	[redacted]
		£ [redacted] m	£ [redacted] m	£ [redacted] m	£ [redacted] m

Table 5 – Additional Smartwires Projects Identified Through Post-NOA Assessment Process

Two projects that were not assessed under the 2018/19 NOA process have also been included in our incremental wider works baseline plan.

The first of these projects is related to our work on Visual Impact Provision (VIP). This initiative involves us carrying out works to mitigate the visual impact of existing transmission overhead line routes. Full details of the VIP project can be found here[6].

Background

One of the VIP projects involves replacing a section of the existing Bramley-Melksham 400kV double circuit overhead line with underground cable, where it passes within the North Wessex Downs AONB. The VIP arrangement only provides funding for like-for-like replacement of existing circuits, i.e. it is not designed to provide funding for us to increase the capability of existing routes.

However, separate from the VIP project we entered an option into the 2018/19 NOA process to increase the capability of the Bramley-Melksham route through replacing the conductor system. The reference code for this project is MBRE and it can be seen in the table above. The latest NOA results, shown in Table 8, indicate that the project is likely to be required as early as 2027 in both FES scenarios most closely aligned to achieving net-zero 2050 targets (i.e. Two Degrees and Community Renewables), and the project received a Hold recommendation. As described earlier, a Hold recommendation is a positive outcome, which indicates that a project has a likelihood of being required in the future. The VIP project is currently scheduled to be delivered by 2024, i.e. ahead of the need to upgrade the capability of the overall route.

Options considered

The options to deliver this combination of investments are:

1. Deliver the VIP project based on the current route rating, and return in the future when NOA triggers the uprating work
2. Deliver the future rating requirement at the same time as the VIP project

[6] https://www.nationalgridet.com/planning-together-riio/visual-impact-provision

3. Delay the VIP project to align to NOA dates.

As the level of risk surrounding the future ratings requirement is relatively low (due to being identified as an optimal investment through NOA in both scenarios consistent with net-zero 2050) and it is likely to be advanced in the next NOA iteration, the T2 plan includes funding for option 2 above – deliver the future rating requirement in the same timescales as the VIP project. The cost included within Incremental Wider Works section of our T2 plan is related to the additional cost of providing the higher rating (i.e. slightly larger cable) only, with the base project cost to be covered within the specific VIP funding application. The additional capital cost of providing the extra capability is summarised in the table below:

Cost of like-for-like VIP cable installation (£m)	Cost of increased capability VIP cable installation (£m)	Incremental cost increase (£m)
[redacted]	[redacted]	15

Table 6 – Cost comparison between lower rated and higher rated installation

Consumer benefit

There are economic benefits to delivering the two requirements as a combined investment. Cost benefit analysis demonstrates a £3m savings by delivering the higher rating requirement at the same time as carrying out the VIP project. This is based on the high cost of having to remobilise in the future to either replace or add to the underground capacity that was installed under VIP. A cost benefit analysis has been carried out to support this decision and is provided in *NGET_A7.02_Incremental Wider Works_CBA01_North Wessex Downs*.

Justification for consumers paying

As with all NOA-driven investments, the ESO determines the overall cheapest solution based on a range of scenarios and project costs. In this instance, the cost benefit of providing the higher rating is likely to become positive in less than 10 years due to the increasing costs of constraints in this part of the network. Without the NOA-driven reinforcement, consumers would be exposed to the cost of these ESO constraints. Similarly, if the VIP work is carried out to include only the existing line rating, consumers will be exposed to the constraint costs associated with the underground section of the route, or else the increased cost of re-installing cables with a higher rating. By carrying out the incremental wider works investment in conjunction with the VIP project, consumers are the beneficiaries of not only reduced constraint costs, but also the improved visual aspect within the North Wessex Downs AONB.

Consequences of not making the investment

Carrying out an undergrounding project of this type is extremely stakeholder-intensive, triggering the need to engage locally with land owners and local authorities, and also wider with bodies such as Natural England, the National Trust and National Park Authorities. The project itself is equally challenging, with large earth excavations often requiring temporary road and footpath diversions, and increased construction traffic that all impact on local communities. Although we expect the VIP project to be well-received locally, the impact during construction, particularly within an area selected for its natural beauty and tranquillity, is considerable.

The consequences therefore of delivering the project across two phases (once to underground and a second time to uprate) would be received negatively not only within the local communities, but also with national groups that have an interest in ecology, habitats and outdoor spaces. The second phase of the project would likely be subject to a high volume of objections from stakeholders, making it very difficult to obtain consents. This raises the possibility of not being able to complete the uprating of the route, and therefore being exposed to constraint costs for an extended period. This is aside from the higher capital cost of delivering the project in this way.

The option to delay the VIP project to align with the NOA driver does not support the extensive stakeholder engagement that has gone on to date for the VIP project in the North Wessex area. Landowners and local communities have been invited to engagement events showcasing the benefits of the project, landowners have granted access to land for surveys, and the local authority has bought into the benefits of carrying out this project. This goodwill and engagement will be difficult to maintain should the project be paused for several years, putting the overall success of the project at risk.

The second project not reviewed through the 2018/19 NOA process is the Uprating of Hinkley Point to Bridwater 275kV circuits to 400kV. This scheme was previously 'bundled' as part of the Hinkley – Seabank strategic wider works project and had not been submitted, as a stand-alone project, to any previous versions of NOA. However, as the need case for this project is not directly linked only to the new Hinkley Point C generation connection it is appropriate to assess the project in NOA.

Through our engagement with the ESO post 18/19 NOA process, we have agreed to enter this project into the 19/20 NOA process and expect it to receive a positive recommendation. ESO issues regular updates on the progress of its NOA assessment work ahead of completion, and has indicated that the scheme will be required in all four FES. This project is therefore included in our baseline plan and is referred to as HSNO. This approach is supported by the ESO. The cost information for this scheme can be seen in Table 7.

NOA Ref.	Description	T1 Spend £m	T2 Spend £m	T3 Spend £m	Total Cost £m
HSNO	Uprating of Hinkley Point to Bridgwater 275kV circuits to 400kV	[redacted]	[redacted]	[redacted]	[redacted]
			£[redacted]m		£[redacted]m

Table 7 – IWW Element of Hinkley Point C SWW Project

<u>Delivery Dates for Projects in our Baseline Plan</u>

The delivery dates for the IWW investments included in our baseline plan were derived using the outputs of the 2018/19 NOA process and analysis of the Common Energy Scenario (CES).

As described previously, a project receiving a *Proceed* recommendation from the NOA indicates the ESO's analysis has determined that project should be delivered by its Earliest In Service Date (EISD).

To ensure that the consumer is not exposed to inefficient constraint costs through late delivery of IWW reinforcements, all projects that received a *Proceed* recommendation in the 2018/19 NOA are included in our business plan with delivery dates in line with the EISD.

Projects with *Delay* and *Hold* recommendations have been identified by NOA as being required but where some uncertainty over optimal timing exists. While no immediate investment decision is required for these projects it is still necessary for us to plan for delivery of these works to avoid unnecessary costs for consumers, deliver an economic network for the CES, and ensure we submit a deliverable T2 business plan.

To determine the timing of these projects in our baseline plan we used our analysis of the CES.

The NOA recommends an optimal delivery date for a project under each of the FES. Therefore, for each boundary, the power flows forecast in the CES were compared against those forecast under each FES (as published in the ESO ETYS document) to identify which of the FES most closely aligned with the CES for that boundary.

Once the most similar FES was determined, the project's optimal delivery date recommended by NOA for that FES was used as the delivery date for that project in our plan.

The following example shows that reinforcement option WYQB (Wymondly Quad Boosters) had the following optimal delivery dates across the four FES:

- Two Degrees – 2024
- Community Renewables – 2025
- Consumer Evolution – 2030
- Steady Progression – 2026

This reinforcement provides capability across the B14 boundary. When we compared the power flows across B14 under the CES they most closely aligned with the flows forecast under the Community Renewables FES. Therefore, a delivery date of 2025 was selected for our business plan.

The table below shows the projects in our baseline plan and, where applicable, the optimal timing identified through the NOA analysis. The grey shading indicates the years prior to the earliest in service date (EISD) for each option (i.e. the years in which an option cannot be delivered).

As described in the previous section, projects HSS2, MHPC, HSNO, and North Wessex VIP were not subject to optimal delivery date analysis in the 2018 NOA. For HSS2, MHPC, and HSNO placement in our plan was determined entirely by our analysis of the Common Energy Scenario. For the North Wessex VIP project the delivery date is aligned with the VIP project that is progressed outside of the RIIO framework.

Project ref. code	NOA rec.	T2 Spend	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Timing in NGET Plan
BMM2	**Proceed**	[redacted]												**2022**
BMM3	**Proceed**	[redacted]												**2023**
BNRC	**Proceed**	[redacted]												**2022**
BTNO	**Proceed**	[redacted]												**2026**
CDRE	**Proceed**	[redacted]												**2022**
HAE2	**Proceed**	[redacted]												**2022**
HAEU	**Proceed**	[redacted]												**2021**
KLRE	**Proceed**	[redacted]												**2020**
NEMS	**Proceed**	[redacted]												**2022**
RTRE	**Proceed**	[redacted]												**2021**
SEEU	**Proceed**	[redacted]												**2021**
THS1	**Proceed**	[redacted]												**2023**
WHTI	**Proceed**	[redacted]												**2021**
SER1	**Delay**	[redacted]												**2022**
BRRE	**Hold**	[redacted]												**2022**
CBEU	**Hold**	[redacted]												**2025**
FMHW	**Hold**	[redacted]												**2026**
HWUP	**Hold**	[redacted]												**2028**
IFHW	**Hold**	[redacted]												**2026**
KWHW	**Hold**	[redacted]												**2022**
MBRE	**Hold**	[redacted]												**2027**
NOR1	**Hold**	[redacted]												**2024**
THRE	**Hold**	[redacted]												**2028**
WYQB	**Hold**	[redacted]												**2025**
WYTI	**Hold**	[redacted]												**2023**
HSS2	**Do Not Start**	[redacted]	Timing in plan determined solely through our analysis of the Common Energy Scenario											**2024**
MHPC	**Do Not Start**	[redacted]												**2021**
HSNO	**N/A**	[redacted]												**2024**
North Wessex VIP	**N/A**	**15**	Aligned with VIP project											**2023**

- Two Degrees
- Community Renewables
- Consumer Evolution
- Steady Progression

Table 8 – Optimal Delivery Dates for Baseline IWW Investments

6. Summary of Baseline Plan

Table 9, below, summarises the IWW projects and costs that make up our T2 baseline proposal (excluding contestable projects).

	T1 Spend (£m)	T2 Spend (£m)	T3 Spend (£m)	Total Project Cost (£m)
Projects identified through 2018/19 NOA	108.3	**450.6**	348.1	971.1
Additional Smartwires projects identified post 2018/19 NOA	[redacted]	[redacted]	[redacted]	[redacted]
North Wessex VIP	0.0	**15.0**	0.0	15.0
Hinkley – Brigwater	[redacted]	[redacted]	[redacted]	[redacted]
Total	£121.7m	**£506.9m**	£348.1m	£1040.8m

Table 9 – Summary of Baseline IWW Investments

Of our proposed T2 investment of £506.9m, £307.6m is associated with projects that received the most positive recommendation made by the NOA process (Proceed). It is considered that there is a high degree of certainty in both the need case and our proposed investment solution for these schemes.

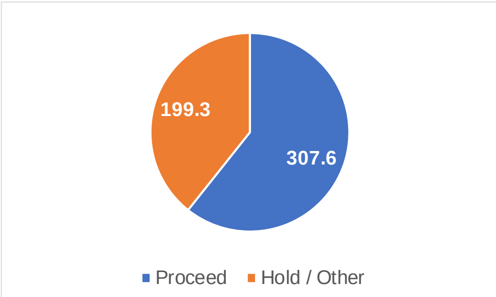


Figure 7 – Split of Proposed Spending by NOA Recommendation

It should be noted that all IWW costs described up to this point include both pre-construction elements and construction elements. Our T1 deal separated these spending phases but we are not proposing that this approach is also applied to T2. Our proposed approach to pre-consents for contestable projects is set out in *NGET_A7.06 Facilitate competition (pre-consents)*.

7. Outputs Delivered by IWW Investments

The projects included in our baseline plan deliver incremental capability increases across a range of system boundaries. In some cases, a single investment will deliver capability across several boundaries. A total of 22.5GW of additional boundary capability will be delivered over the T2 period.

The T2 outputs delivered by the baseline projects specified in Section 4 are shown below. Projects that do not deliver an output in the T2 period are not shown in this table.

Please note that the North Wessex VIP project is excluded from this table as it does not deliver a stand-alone output. The delivery of the increased capability cable section facilitates the future delivery of project MBRE (i.e. the upgrade of the remaining Melksham – Bramley overhead line sections). Any output would be recorded on delivery of MBRE.

Option	B6	B7	B7a	B8	EC5	B12a	B13	SC1	SC2	SC3	LE1	B14	B14e	B15
BMM2					550						290			
BMM3					178									
BNRC								2120	400					1726
BRRE					228									
CBEU				580										
CDRE				1131										
HAE2	409		68											
HAEU	550	236												
HSNO							960	770						
HSS2	304													
KWHW				346										
MHPC	600													
NEMS		211	1035											
NEPC		425	972											
NOR1			161											
RTRE											1220			
SEEU									400					
SER1								1970				390		
THS1				586										
WHTI	771	506	246											
WYQB								1137					187	
WYTI								369					415	

Table 10 – Baseline IWW Investments T2 Outputs[7]

8. Value Delivered by IWW Investments

To quantify the consumer benefits of the IWW investments in our baseline plan, we used the outputs of the ESO NOA (2018/19) process across the 4 FES. Specifically, we utilised the present value of future constraint cost savings discounted over 40 years – provided by the ESO. The projects in our T2 plan account for future constraint cost savings of at least £525m/annum (i.e. £21bn/40 years in the CE scenario). We have more than halved this in our main business plan narrative, to £250m/annum, to provide a conservative estimate.

[7] Project NEPC delivers an output in T2 but all spend occurs in the T1 period. Therefore, NEPC is included in our T2 outputs but is not included in the costs described in this justification report.

			Present Value of Future Constraint Savings (£m)			
NOA Ref.	T2 Spend (£m)	Project Cost (£m)	TD	SP	CE	CR
BMM2	[redacted]	[redacted]	4,029	9,483	351	3,276
BMM3			1,055	1,964	36	839
BNRC			620	590	363	897
BRRE			1,493	0	60	1,129
BTNO			13,398	26,748	5,520	10,915
CBEU			-	-	-	-
CDRE			69	37	6	54
FMHW			0	0	-	0
HAE2			154	39	46	110
HAEU			1,414	593	319	339
HSNO			-	-	-	-
HSS2			-	-	-	-
HWUP			7,838	760	2,691	3,236
IFHW			0	0	-	2
KLRE			79,456	2,349	1,436	3,164
KWHW			6	1	0	3
MBRE			131	-	150	71
MHPC			-	-	-	-
NEMS			15	-	0	18
NOR1			7	-	-	8
RTRE			5,972	1,633	8,806	3,856
SEEU			60	163	306	73
SER1			353	10	4	14
THRE			2,792	2,318	-23	3,186
THS1			41	-5	584	20
WHTI			258	561	299	324
WYQB			1,482	1,387	353	1,831
WYTI			861	495	297	781
TOTALS	**492**	**960.4**	**121,507**	**49,124**	**21,604**	**34,147**

Table 11 – Forecast Constraint Savings Delivered by Baseline IWW Investments

This table clearly demonstrates that the Present Value of future constraint savings is higher than the investment cost proposed.

9. Managing Uncertainty

We are proposing a suite of uncertainty mechanisms that allocate risk to whomever is best placed to manage it to deal with cost and volume uncertainty in the T2 period.

Consumers can best manage supply and demand volume uncertainty because this reflects 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.

As the NOA is an annual process there is a risk that the volume of boundary capability required in our baseline plan could change. This could result from changes to the FES, leading to optimal delivery dates moving or even different options being recommended by the ESO. Additionally, the ESO has stated their intention to expand the remit of the NOA process in future, allowing solutions from 3rd party providers such as DNOs or flexibility providers to be assessed against TO solutions.

As the volume of boundary capability investments we will have to deliver in the T2 period is dependent on the above, we have developed a volume driver uncertainty mechanism based on unit cost allowances to deal with this uncertainty, as shown in Figure 8 below.

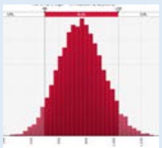
Incremental Wider Works (Boundary Capacity) – Unit Cost Allowance (UCA)

Key stats:	
Models considered	7
Input data points (projects)	77

Uncertainty characteristics

i) Risk and ownership
- System need and best whole system solution uncertain
- Requirements driven by annual ESO NOA process
- Network company manages cost risk, whilst consumer best to manage volume risk

ii) Materiality
- Range of uncertainty is £541m *(90% of Monte Carlo simulations have a total cost between £497m and £1,038m)*



T2 CAPEX probability distribution

(output of Monte Carlo analysis)

iii) Frequency and probability
- Annually as part of the ESO NOA process
- Near 100% probability of some change in future requirements

T1 experience and learning

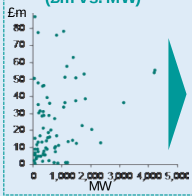
i) T1 experience
- Per boundary UCA reduced allowances by >£190m as system needs changed
- Output based UCA maintained ability to innovate (e.g. Smartwires); leading to considerable consumer benefit
- Mechanism not sufficiently cost-reflective / overly sensitive to energy scenario changes
- No ability to add new boundaries indicated by the ESO through NOA

ii) Learnings for T2
- More rigorous, analytical approach to developing and testing UCAs, not limited to data on single boundary, required
- More cost-reflective, output based, UCA would better protect both consumers and companies
- Approach must work with annual NOA process and allow for new boundaries to be added
- Revenue calculation based on latest forecast of outputs can smooth customer charges

T2 proposals

i) Proposed mechanism and benefits
- Combined pre-construction and construction mechanism
- Separate UCAs for route and non-route projects, using average boundary length to enhance cost reflectivity
- Expansion factors applied to length in order to reflect increased cost of cabling to simplify mechanism
- Established regression techniques to design and Monte Carlo simulations to test for the most accurate and resilient UCA

Inputs (£m vs. MW)

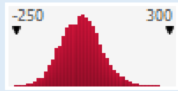


Proposed Design

Route reinforcements:
0.7284 £m/ln(MWkm) + 0.4102 £m/km

Non-route reinforcements:
- 3.7397 £m/ln(MW)

Testing (cost vs. allowance)



Mean: -£9.48m

Std. Dev.: £64.2m

- Roll-forward T1 efficiencies into T2 dataset for calculating UCAs
- Revenue calculated based on latest 5-year RRP forecast of outputs in order to minimise customer charging volatility

ii) Drawbacks and mitigations
- Minor increase in complexity of mechanism outweighed by significant increase in cost-reflectivity and mitigated through simplifications in other areas, such as approach to cables

Figure 8 – Summary of Proposed IWW Uncertainty Mechanism

The detail of our analysis and proposals to manage energy supply and demand uncertainty is set out in the annex NGET_ET.12 Uncertainty mechanisms and accompanying workbooks showing the detail or our development and statistical analysis.

1. Conclusion

We have used the input of the ESO's independent NOA process (2018/19 version) and the Common Energy Scenario to determine our baseline plan for IWW investments.

We have provided an extensive range of investment options into that process to allow the ESO to determine the most economic and efficient investment strategy for providing transmission boundary capability.

Our baseline plan includes projects that received positive investment recommendations following the ESO's independent cost benefit analysis.

Our baseline investment plan is summarised in Table 13, below:

	T1 Spend (£m)	T2 Spend (£m)	T3 Spend (£m)	Total Project Cost (£m)
Projects identified through 2018/19 NOA	108.3	**450.6**	348.1	971.1
Additional Smartwires projects identified post 2018/19 NOA	[redacted]	[redacted]	[redacted]	[redacted]
North Wessex VIP	0.0	**15.0**	0.0	15.0
Hinkley – Brigwater	[redacted]	[redacted]	[redacted]	[redacted]
Total	£121.7m	**£506.9m**	£348.1m	£1040.8m

Table 13 – Summary of Baseline Proposal

A total T2 baseline spend of £507m is proposed.

£307.6m of this spend is associated with schemes that received the most positive recommendation made by the NOA process (Proceed). It is considered that there is a high degree of certainty in both the need case and our proposed investment solution for these schemes.

£199.3m is associated with schemes that have been identified as part of the optimal investment strategies to deliver maximum value for consumers but that do not require immediate investment actions.

All schemes entered into the NOA process had robust cost estimates and delivery plans developed in line with the process described in *Chapter 14 Our total costs and how we provide value for money* of our main business plan narrative.

We have not included any costs for projects meeting contestability criteria within our incremental wider works proposals. Our proposed approach to pre-consents for contestable projects is set out in *NGET_A7.06 Facilitate competition (pre-consents)*.

We have developed a robust unit cost allowance to manage boundary capacity volume uncertainty in the T2 period. This mechanism will automatically adjust allowances up and down depending on customer requirements.