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nationalgrid

Strategic Options Technical Appendix 2020/2021 price base

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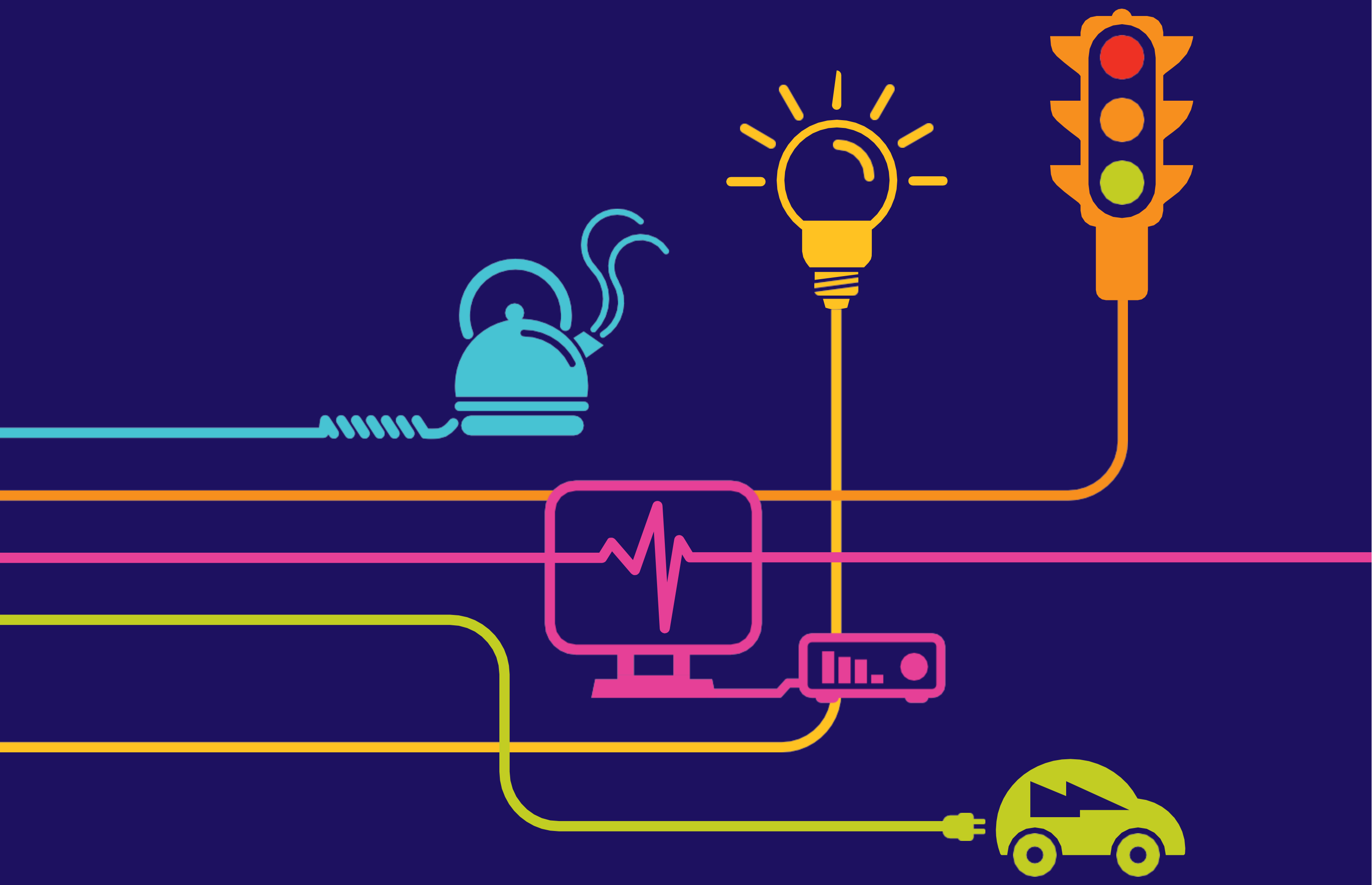

Strategic Options Appendices

Price Base 2020/21

Table of Contents

Table of Contents

Appendix A – Summary of National Grid Electricity Transmission Legal Obligations

A.1 Transmission of electricity in Great Britain requires permission by a licence granted under Section 6(1)(b) of the Electricity Act 1989 ("the Electricity Act").

A.2 National Grid Electricity Transmission (NGET) has been granted a transmission licence and is therefore bound by the legal obligations primarily set out in the Electricity Act and transmission licence.

A.3 NGET owns and maintains the transmission system in England and Wales.

A.4 NGET has a statutory duty to develop and maintain an efficient, coordinated and economical system of electricity transmission under Section 9 of the Electricity Act. These duties, which are documented in General and Standard Licence Conditions, are summarised in the following paragraphs.

A.5 General Condition B12 (System Operator – Transmission Owner Code) NGESO is the operator of the Transmission system in Scotland, England and Wales and is a legally separate entity for NGET. The System Operator is required to maintain a System Operator – Transmission Owner Code "STC" setting out terms by which transmission owners and the system operator co-ordinate activities and disputes.

A.6 Standard Condition D3 (Transmission system security standard and quality of service) requires NGET to at all times plan, develop the transmission system in accordance with the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS). This condition includes specific arrangements (Connect and Manage Derogation) that permit NGET to offer to connect a customer to the transmission system before all reinforcement works to achieve compliance with the NETS SQSS are complete. Such permissions are subject to NGET publishing Connect and Manage Derogations and reporting to Ofgem.

A.7 Standard Condition D4A (Obligations in relation to offers for connection) of NGET's transmission licence sets out obligations on NGET regarding provision of offers to provide connections to and/or use of the transmission system supporting the system operator standard condition C8

(Requirement to offer terms). In summary, where a party applies for a connection NGET is to offer to enter into an agreement(s) to connect, or to modify an existing connection, to the transmission system and the offer shall make detailed provision regarding the:

- carrying out of works required to connect to the transmission system
- carrying out of works (if any) in connection with the extension or reinforcement of the transmission system, and
- where the system operator request the same, the installation of meters (if any) on the licensee's transmission system to enable the system operator to measure electricity being accepted or leaving the system at specified point(s).
- date by when any works required permitting access to the transmission system (including any works to reinforce or extend the transmission system) shall be completed.
- Such costs as may be directly or indirectly incurred carrying out the works, the extension or reinforcement of the licensee's transmission system or the provision and installation, maintenance and repair or (as the case may be) removal following disconnection of any electric lines, electric plant or meters, which works are detailed in the offer;

A.8 Standard Condition D15 (Obligations relating to the preparation of TO offers during the transition period) this is an obligation to support the system operator in meeting its obligations under system operator standard condition C18 (Requirement to offer terms for connection or use of the GB Transmission system during the transition period) as set out in the license and STC.

A.9 Standard Condition D16 (Requirements of a connect and manage connection) supplements the obligations applicable to NGET when making an offer of connection to the transmission system. The connect and manage connection regime was introduced in August 2010. One intention of this regime is to facilitate the timely connection of new generation projects.

A.10 Standard Condition D17 (Whole System Obligations) this condition sets an obligation on transmission owners to coordinate and cooperate with transmission licensees and electricity distributors in order to build common understanding of where actions taken by one could have cross-network impacts. All licensees should identify actions and processes to advance the efficient and economical operation of the total system.

A.11 As well as the technical standards described above, Schedule 9 of the Electricity Act 1989 requires NGET, when formulating proposals for new lines and other works, to:

"…have regard to the desirability of preserving natural beauty, of conserving flora, fauna, and geological or physiographical features of special interest and of protecting sites, buildings and objects of architectural, historic or archaeological interest; and to do what [it] reasonably can to mitigate any effect which the proposals would have on the natural beauty of the countryside or on any such flora, fauna, features, sites, buildings or objects".

A.12 NGET's Stakeholder, Community and Amenity Policy ("the Policy") sets out how the company will meet the duty to the environment placed upon it. These commitments include:

- only seeking to build new lines and substations where the existing transmission infrastructure cannot be upgraded technically or economically to meet transmission security standards
- where new infrastructure is required seek to avoid areas nationally or internationally designated for their landscape, wildlife or cultural significance, and
- minimising the effects of new infrastructure on other sites valued for their amenity.

A.13 The Policy also refers to the application of best practice methods to assess the environmental impacts of proposals and identify appropriate mitigation and/or offsetting measures. Effective consultation with stakeholders and the public is also promoted by the Policy.

Appendix B – Requirement for Development Consent

B.1 Developing the transmission system in England and Wales may require one or more statutory consents, depending on the type and scale of the project. These may include planning permission under the Town and Country Planning Act 1990, a marine licence under the Marine and Coastal Access Act 2009, a Development Consent Order ("DCO") under the Planning Act 2008 and a variety of consents under related legislation. A 400kV overhead line will require a Development Consent Order. Such an order may also incorporate consent for associated development.

B.2 Six National Policy Statements ("NPS") for energy infrastructure were published by the Secretary of State for Energy and Climate Change in July 2011. The most relevant NPSs for transmission infrastructure are the Overarching National Policy Statement for Energy (EN-1) and the National Policy Statement for Electricity Networks Infrastructure (EN-5), which must be read in conjunction with EN-1.

B.3 Section 104(3) of the Planning Act 2008 states that the decision maker must determine an application for a DCO in accordance with any relevant NPS, except in certain specified circumstances. These include where the adverse impact of the proposed development would outweigh its benefits. The energy NPSs therefore provide the primary policy basis for decisions on DCO applications for transmission projects. The NPSs may also be a material consideration for decisions on other types of development consent in England and Wales (including offshore projects) and for planning applications under the 1990 Act.

Demonstrating the Need for a Project

B.4 Part 3 of EN-1 sets out Government policy on the need for new nationally significant energy infrastructure projects. Paragraph 3.1 confirms that the UK needs all the types of energy infrastructure covered by the NPS to achieve energy security at the same time as dramatically reducing greenhouse gas emissions. It states that "substantial weight" should be given to the contribution which projects would make towards satisfying this need. A need for new transmission infrastructure is set out in EN-1 and EN-5, and a need for new nuclear and offshore/onshore wind generation is set out in EN-1, EN-3 and EN-6. The need for new transmission infrastructure for this project is described in section 3 of this Report.

Assessment Principles

B.5 Part 4 of EN-1 sets out the assessment principles to be applied in determining DCO applications for energy NSIPs. Paragraphs 2.3 - 2.5 of EN-5 do the same in the specific context of electricity networks infrastructure.

B.6 Principles of particular importance for transmission infrastructure projects include:

Presumption in Favour of Development

B.7 Section 4.1 of EN-1 provides a presumption in favour of granting consent for energy NSIPs (subject to specific policies in an NPS indicating otherwise or to the specific exceptions in the Planning Act, including where the adverse impacts outweigh the benefits). Adverse impacts include long term and cumulative impacts but take into account mitigation measures. Potential benefits include the contribution to meeting the need for energy infrastructure, job creation and long term wider benefits.

Consideration of Alternatives

B.8 Section 4.4 of EN-1 states that, from a planning policy perspective alone, there is no general requirement to consider alternatives or to establish whether the proposed project represents the best option. However, in relation to transmission projects, paragraph 2.8.4 of EN-5 states that, "wherever the nature or proposed route of an overhead line proposal makes it likely that its visual impact will be particularly significant, the applicant should have given appropriate consideration to the potential costs and benefits of other feasible means of connection or reinforcement, including underground and subsea cables where appropriate."

B.9 Section 4.4 of EN-1 also makes clear that there will be circumstances where a promoter is specifically required to consider alternatives. These may include requirements under the Habitats Directive and the Birds Directive[24].

Good Design

B.10 Section 4.5 of EN-1 stresses the importance of 'good design' for energy infrastructure and explains this goes beyond aesthetic considerations and is also important for fitness for purpose and sustainability. It is acknowledged that the nature of much energy infrastructure development will often limit the extent to which it can contribute to the enhancement of the quality of the area. Section 2.5 of EN-5 identifies a particular need to demonstrate the principles of good design in the approach to mitigating the potential adverse impacts which can be associated with overhead lines.

Climate Change

B.11 Section 4.8 of EN-1 explains how the effects of climate change should be taken into account and section 2.4 of EN-5 expands on this in the specific context of electricity networks infrastructure. This requires DCO applications to set out the vulnerabilities / resilience of the proposals to flooding, effects of wind on overhead lines, higher average temperatures leading to increased transmission losses and earth movement or subsidence caused by flooding or drought (for underground cables).

Networks DCO Applications Submitted in Isolation

B.12 Section 2.3 of EN-5 confirms that it can be appropriate for DCO applications for new transmission infrastructure to be submitted separately from applications for the generation that this infrastructure will serve. It explains that the need for the transmission project can be assessed on the basis of both contracted and reasonably anticipated generation.

[24] Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora; Council Directive 2009/147/EC on the conservation of wild birds.

Electricity Act Duties

B.13 Paragraph 2.3.5 of EN-5 recognises National Grid's duties pursuant to section 9 of the Electricity Act to bring forward efficient and economical proposals in terms of network design, taking into account current and reasonably anticipated future generation demand, and its duty to facilitate competition and so provide a connection whenever and wherever one is required.

Adverse Impacts and Potential Benefits

B.14 Part 5 of EN-1 covers the impacts that are common across all energy NSIPs and sections 2.6-2.9 of EN-5 consider impact in the specific context of electricity networks infrastructure.

B.15 Those impacts identified in EN-1 include air quality and emissions, biodiversity and geological conservation, civil and military aviation and defence interests, coastal change (to the extent in or proximate to a coastal area), dust, odour, artificial light, smoke, steam and insect infestation, flood risk, historic environment, landscape and visual, land use, noise and vibration, socio-economic effects, traffic and transport, waste management and water quality and resources. The extent to which these impacts are relevant to a particular stage of a project, or are a relevant differentiator at a particular stage of the options appraisal process, will vary. In particular, some of these impacts are scoped out of this stage of the options appraisal process for this project. EN-5 considers specific potential impacts of electricity networks on biodiversity and geological conservation, landscape and visual, noise and vibration, and electric and magnetic fields.

B.16 Potential impacts of particular importance for transmission infrastructure projects include:

Landscape and Visual

B.17 Paragraph 2.8.2 of EN-5 states that the Government does not believe that development of overhead lines is generally incompatible in principle with National Grid's statutory duty under section 9 of the Electricity Act 1989 to have regard to amenity and to mitigate impacts but recognises that overhead lines can give rise to adverse landscape and visual impacts, dependent upon their scale, siting, degree of screening and the nature of the landscape and local environment through which they are routed. In relation to alternative technologies for transmission projects, paragraph 2.8.9 states that, "each project should be assessed individually on the basis of its specific circumstances and taking account of the fact that Government has not laid down any general rule about when an overhead line should be considered unacceptable. The IPC should, however, only refuse consent for overhead line proposals in favour of an underground or subsea line if it is satisfied that the benefits from the non-overhead line alternative will clearly outweigh any extra economic, social and environmental impacts and the technical difficulties are surmountable." Paragraph 2.8.7 endorses the Holford Rules which are a set of "common sense" guidelines for routeing new overhead lines.

Appendix C – Technology Overview

C.1 This section provides an overview of the technologies available for the strategic options described in this Report. It provides a high-level description of the relevant features of each technology. The costs for each technology are presented in Appendix D.

C.2 The majority of electricity systems throughout the world are AC systems. Consumers have their electricity supplied at different voltages depending upon the amount of power they consume e.g. 230V for domestic customers and 11 kV for large factories and hospitals. The voltage level is relatively easy to change when using AC electricity, which means a more economical electricity network can be developed for customer requirement. This has meant that the electrification of whole countries could be and was delivered quickly and efficiently using AC technology.

C.3 DC electricity did not develop as the means of transmitting large amounts of power from generating stations to customers because DC is difficult to transform to a higher voltage and bulk transmission by low voltage DC is only effective for transporting power over short distances. However, DC is appropriate in certain applications such as the extension of an existing AC system or when providing a connection to the transmission system.

C.4 In terms of voltage, the transmission system in England and Wales operates at both 275 kV and 400 kV. The majority of National Grid's transmission system is now constructed and operated at 400 kV, which facilitates higher power transfers and lower transmission losses.

C.5 There are a number of different technologies that can be used to provide transmission connections. These technologies have different features which affect how, when and where they can be used. The main technology options for electricity transmission are:

- Overhead lines
- Underground cables
- Gas Insulated Lines (GIL) and
- High Voltage Direct Current (HVDC).

C.6 This appendix provides generic information about each of these four technologies. Further information, including a more detailed technical review is available in a series of factsheets that can be found at the project website referenced at the beginning of this Report.

Overhead lines

C.7 Overhead lines form the majority of the existing transmission system circuits in Great Britain and in transmission systems across the world. As such there is established understanding of their construction and use.

C.8 Overhead lines are made up of three main component parts which are; conductors (used to transport the power), pylons (used to support the conductors) and insulators (used to safely connect the conductors to pylons)

C.9 Figure C.1 shows a typical pylon used to support two 275 kV or 400 kV overhead line circuits. This type of pylon has six arms (three either side), each carrying a set (or bundle) of conductors.

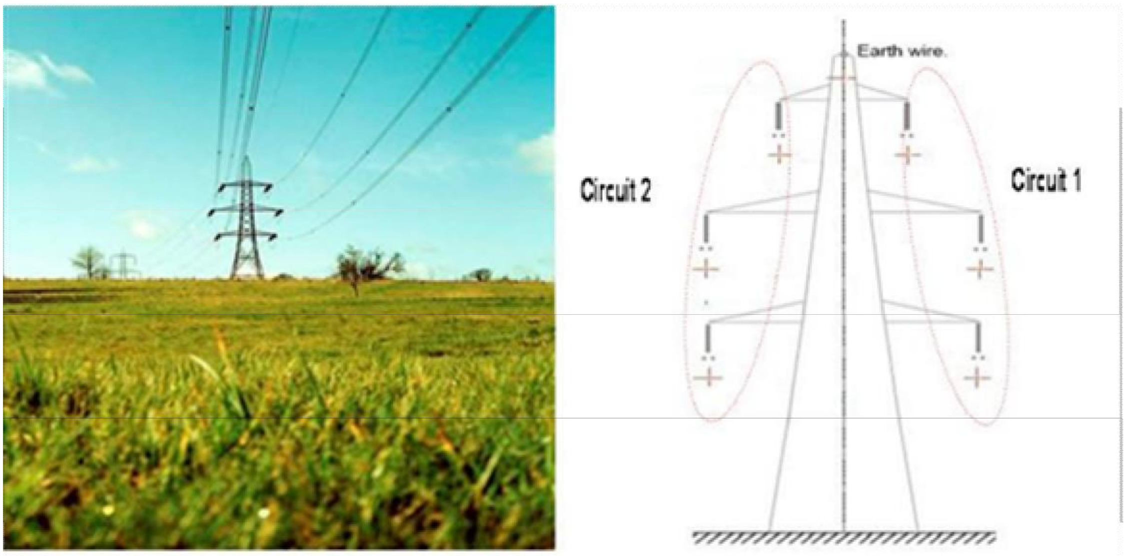

Figure C.1: Example of a 400 kV Double-circuit Tower

C.10 The number of conductors supported by each arm depends on the amount of power to be transmitted and will be either two, three or four conductors per arm. Technology developments have increased the capacity that can be carried by a single conductor and therefore, new overhead lines tend to have two or three conductors per arm.

C.11 With the conclusion of the Royal Institute of British Architects (RIBA) pylon design competition[25] and other recent work with manufacturers to develop alternative pylon designs, National Grid is now able to consider a broader range of pylon types, including steel lattice and monopole designs. The height and width is different for each pylon type, which may help National Grid to manage the impact on landscape and visual amenity better. Figure C.2, below, shows an image on the winning design from the RIBA pylon design competition, a monopole design called the T-pylon (currently being developed by National Grid).

Figure C.2: The T-pylon

C.12 Pylons are designed with sufficient height to ensure that the clearances between each conductor and between the lowest conductor and the ground, buildings or structures are adequate to prevent electricity jumping across. The minimum clearance between the lowest conductor and the ground is normally at the mid-point between pylons. There must be sufficient clearance between objects and the lowest point of the conductor as shown in Figure C.3.

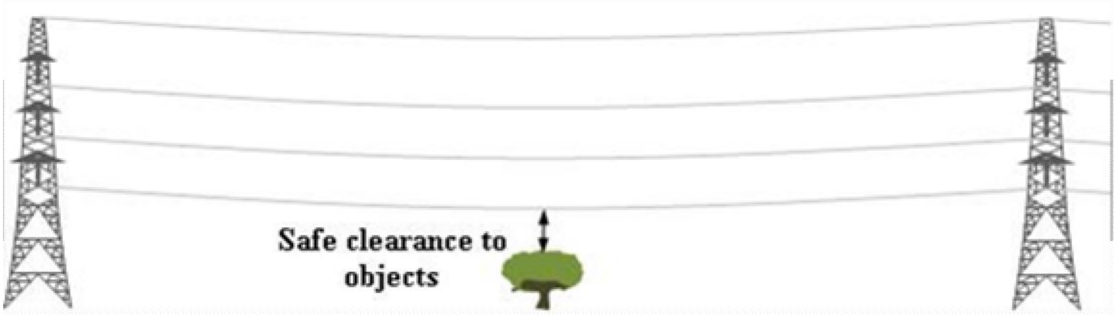

Figure C.3: Safe height between lowest point of conductor and other obstacle ("Safe Clearance")

C.13 The distance between adjacent pylons is termed the '*span length*'. The span length is governed by a number of factors, the principle ones being pylon height, number and size of conductors (i.e. weight), ground contours and changes in route direction. A balance must therefore be struck between the size and physical presence of each tower versus the number of towers; this is a decision based on both visual and economic aspects. The typical 'standard' span length used by National Grid is approximately 360m.

C.14 Lower voltages need less clearance and therefore the pylons needed to support 132 kV lines are not as high as traditional 400 kV and 275 kV pylons. However, lower voltage circuits are unable to transport the same levels of power as higher voltage circuits.

C.15 National Grid has established operational processes and procedures for the design, construction, operation and maintenance of overhead lines. Circuits must be taken out of service from time to time for repair and maintenance. However, short emergency restoration times are achievable on overhead lines as compared, for example, to underground cables. This provides additional operational flexibility if circuits need to be rapidly returned to service to maintain a secure supply of electricity when, for example, another transmission circuit is taken out of service unexpectedly.

C.16 In addition, emergency pylons can be erected in relatively short timescales to bypass damaged sections and restore supplies. Overhead line maintenance and repair therefore does not significantly reduce security of supply risks to end consumers.

C.17 Each of the three main components that make up an overhead line has a different design life, which are:

- Between 40 and 50 years for overhead line conductors
- 80 years for pylons
- Between 20 and 40 years for insulators

C.18 National Grid expects an initial design life of around 40 years, based on the specified design life of the component parts. However, pylons can be easily refurbished and so substantial pylon replacement works are not normally required at the end of the 40 year design life.

Underground Cables

C.19 Underground cables at 275 kV and 400 kV make up approximately 10% of the existing transmission system in England and Wales, which is typical of the proportion of underground to overhead equipment in transmission systems worldwide. Most of the underground cable is installed in urban areas where achieving an overhead route is not feasible. Examples of other situations where underground cables have been installed, in preference to overhead lines, include crossing rivers, passing close to or through parts of nationally designated landscape areas and preserving important views.

C.20 Underground cable systems are made up of two main components – the cable and connectors. Connectors can be cable joints, which connect a cable to another cable, or overhead line connectors in a substation.

C.21 Cables consist of an electrical conductor in the centre, which is usually copper or aluminium, surrounded by insulating material and sheaths of protective metal and plastic. The insulating material ensures that although the conductor is operating at a high voltage, the outside of the cable is at zero volts (and therefore safe). Figure C.4 shows a cross section of a transmission cable and a joint that is used to connect two underground cables.

4.1 **Figure C.4: Cable Cross-Section and Joint**

C.22 Underground cables can be connected to above-ground electrical equipment at a substation, enclosed within a fenced compound. The connection point is referred to as a cable sealing end. Figure C.5 shows two examples of cable sealing end compounds.

Figure C.5: Cable Sealing End Compounds

C.23 An electrical characteristic of a cable system is capacitance between the conductor and earth. Capacitance causes a continuous 'charging current' to flow, the magnitude of which is dependent on the length of the cable circuit (the longer the cable, the greater the charging current) and the operating voltage (the higher the voltage the greater the current). Charging currents have the effect of reducing the power transfer through the cable.

C.24 High cable capacitance also has the effect of increasing the voltage along the length of the circuit, reaching a peak at the remote end of the cable.

C.25 National Grid can reduce cable capacitance problems by connecting reactive compensation equipment to the cable, either at the ends of the cable, or, in the case of longer cables, at regular intervals along the route. Specific operational arrangements and switching facilities at points along the cable circuit may also be needed to manage charging currents.

C.26 Identifying faults in underground cable circuits often requires multiple excavations to locate the fault and some repairs require removal and installation of new cables, which can take a number of weeks to complete.

C.27 High voltage underground cables must be regularly taken out of service for maintenance and inspection and, should any faults be found and depending on whether cable excavation is required, emergency restoration for security of supply reasons typically takes a lot longer than for overhead lines (days rather than hours).

C.28 The installation of underground cables requires significant civil engineering works. These make the construction times for cables longer than overhead lines.

C.29 The construction swathe required for two AC circuits comprising two cables per phase will be between 35-50 m wide.

C.30 Each of the two main components that make up an underground cable system has a design life of between 40 and 50 years.

C.31 Asset replacement is generally expected at the end of design life. However, National Grid's asset replacement decisions (that are made at the end of design life) will also take account of actual asset condition and may lead to actual life being longer than the design life.

Gas Insulated Lines (GIL)

C.32 GIL is an alternative to underground cable for high voltage transmission. GIL has been developed from the well-established technology of gas-insulated switchgear, which has been installed on the transmission system since the 1960s.

C.33 GIL uses a mixture of nitrogen and sulphur hexafluoride (SF_6) gas to provide the electrical insulation. GIL is constructed from welded or flanged metal tubes with an aluminium conductor in the centre. Three tubes are required per circuit, one tube for each phase. Six tubes are therefore required for two circuits, as illustrated in Figure C.6 below.

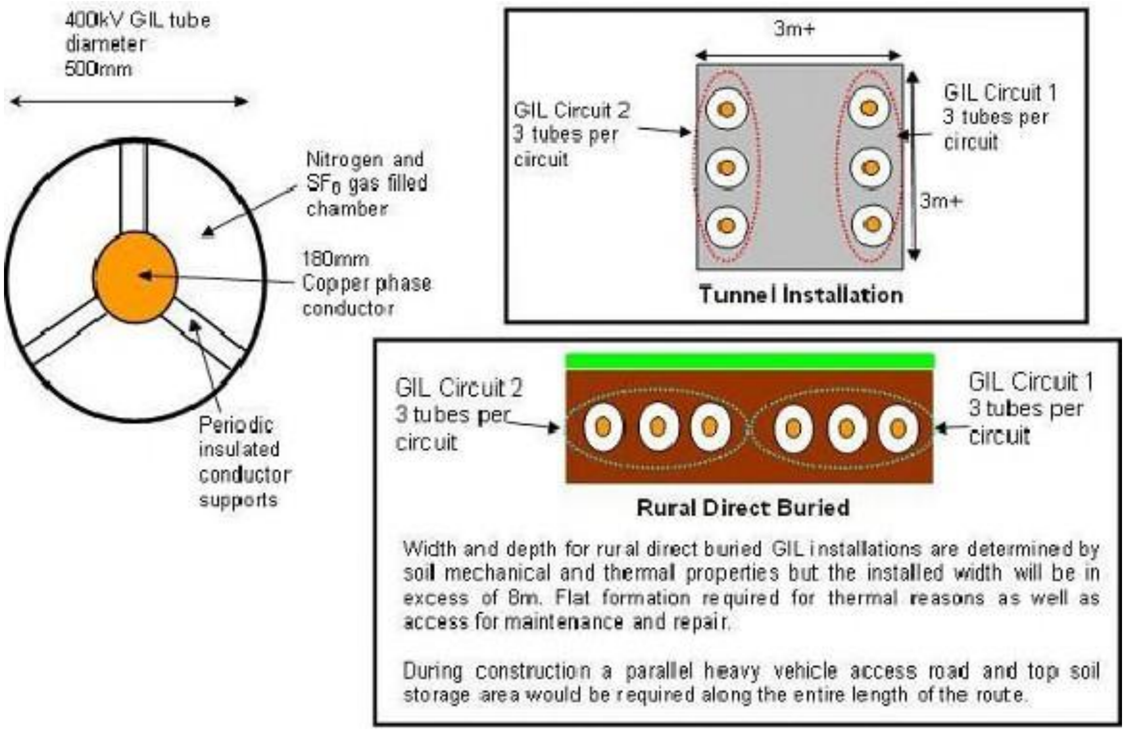

Figure C.6: Key Components of GIL[27]

C.34 GIL tubes are brought to site in 10 – 20 m lengths and they are joined in situ. It is important that no impurities enter the tubes during construction as impurities can cause the gas insulation to fail. GIL installation methods are therefore more onerous than those used in, for example, natural gas pipeline installations.

[27] The distances are based on initial manufacturer estimates of tunnel and buried GIL dimensions which would be subject to full technical appraisal by National Grid and manufacturers to achieve required ratings which may increase the separation required. It should be noted that the diagram does not show the swathe of land required during construction. Any GIL tunnel installations would have to meet the detailed design requirements of National Grid for such installations.

C.35 A major advantage of GIL compared to underground cable is that it does not require reactive compensation.

C.36 The installation widths over the land can also be narrower than cable installations, especially where more than one cable per phase is required.

C.37 GIL can have a reliability advantage over cable in that it can be re-energised immediately after a fault (similar to overhead lines) whereas a cable requires investigations prior to re-energisation. If the fault was a transient fault it will remain energised and if the fault was permanent the circuit will automatically and safely de-energise again.

C.38 There are environmental concerns with GIL as the SF_6[28] gas used in the insulating gas mixture is a potent 'greenhouse gas'. Since SF_6 is an essential part of the gas mixture GIL installations are designed to ensure that the risk of gas leakage is minimised.

C.39 There are a number of ways in which the risk of gas leakage from GIL can be managed, which include:

(i) use of high-integrity welded joints to connect sections of tube;

(ii) designing the GIL tube to withstand an internal fault; and

(iii) splitting each GIL tube into a number of smaller, discrete gas zones that can be independently monitored and controlled.

C.40 At decommissioning the SF_6 can be separated out from the gas mixture and either recycled or disposed of without any environmental damage.

C.41 GIL is a relatively new technology and therefore has limited historical data, meaning that its operational performance has not been empirically proven. National Grid has two GIL installations on the transmission system which

[28] SF6 is a greenhouse gas with a global warming potential, according to the Intergovernmental Panel on Climate Change, Working Group 1 (Climate Change 2007, Chapter 2.10.2), of 22,800 times that of CO2. **www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html**

are 545 m and 150 m long[29]. These are both in electricity substations; one is above ground and the other is in a trough. The longest directly buried transmission voltage GIL in the world is approximately one kilometre long and was recently installed on the German transmission system around Frankfurt Airport.

C.42 In the absence of proven design life information, and to promote consistency with assessment of other technology options, National Grid assesses GIL over a design life of up to 40 years.

High Voltage Direct Current ("HVDC")

C.43 HVDC technology can provide efficient solutions for the bulk transmission of electricity between AC electricity systems (or between points on an electricity system).

C.44 There are circumstances where HVDC has advantages over AC, generally where transmission takes place over very long distances or between different, electrically-separate systems, such as between Great Britain and countries in Europe such as France, Belgium, The Netherlands, Ireland etc...

C.45 HVDC links may also be used to connect a generating station that is distant from the rest of the electricity system. For example, very remote hydro-electric schemes in China are connected by HVDC technology with overhead lines.

C.46 Proposed offshore wind farms to be located over 60 km from the coast of Great Britain are likely to be connected using HVDC technology as an alternative to an AC subsea cable. This is because AC subsea cables over 60 km long have a number of technical limitations, such as high charging currents and the need for mid-point compensation equipment.

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[29] The distances are based on initial manufacturer estimates of tunnel and buried GIL dimensions which would be subject to full technical appraisal by National Grid and manufacturers to achieve required ratings which may increase the separation required. It should be noted that the diagram does not show the swathe of land required during construction. Any GIL tunnel installations would have to meet the detailed design requirements of National Grid for such installations.

C.47 The connection point between AC and DC electrical systems has equipment that can convert AC to DC (and vice versa), known as a converter. The DC electricity is transmitted at high voltage between converter stations. Convertor stations can use two types of technology. "Classic" or Current Source Convertors (CSC) were the first type of HVDC technology developed and this design was used for NGETs Western Link. Voltage Source Convertors (VSC) are a newer design and offer advantages over the previous CSC convertors, as they can better support weaker systems and offer more flexibility in the way they operate, including direction of power flow.

Figure C.7: VSC convertor Station

C.48 HVDC can offer advantages over AC underground cable, such as:

- a minimum of two cables per circuit is required for HVDC whereas a minimum of three cables per circuit is required for AC.
- reactive compensation mid-route is not required for HVDC.
- cables with smaller cross sectional areas can be used (compared to equivalent AC system rating).
- This allows HVDC cables to be more easily installed for subsea applications than AC cables for a given capacity.

C.49 HVDC cables are generally based upon two technology types Mass Impregnated and Extruded technologies. VSC technology may utilise either technology type, whereas CSC technology tends to be limited to Mass Impregnated cables due to the way poles are reversed for change of power flow direction.

Figure C.8: HVDC Cable Laying Barge at transition between shore and sea cables

C.50 HVDC systems have a design life of about 40 years. This design life period is on the basis that large parts of the converter stations (valves and control systems) would be replaced after 20 years.

Appendix D – Economic Appraisal

D.1 As part of the economic appraisal of Strategic Options, National Grid makes comparative assessments of the lifetime costs associated with each technology option that is considered to be feasible.

D.2 This section provides an overview of the methods that National Grid uses to estimate lifetime costs as part the economic appraisal of a Strategic Option. It also provides a summary of generic capital cost information for transmission system circuits for each technology option included in Appendix C and an overview of the method that National Grid uses to assess the Net Present Value ("NPV") of costs that are expected to be incurred during the lifetime of new transmission assets.

D.3 The IET, PB/CCI Report[30] presents cost information in size of transmission circuit capacity categories for each circuit design that was considered as part of the independent study. To aid comparison between the cost data presented in the IET PB/CCI Report and that used by National Grid for appraisal of Strategic Options, this appendix includes cost estimates using National Grid cost data for circuit designs that are equivalent to those considered as part of the independent study. Examples in this Appendix are presented using the category size labels of "Lo", "Med" and "Hi" used in the IET PB/CCI Report.

Lifetime Costs for Transmission

D.4 For each technology option appraised within a Strategic Option, National Grid estimates total lifetime costs for the new transmission assets. The total lifetime cost estimate consists of the sum of the estimates of the:

- initial capital cost of developing, procuring, installing and commissioning the new transmission assets, and

[30] "Electricity Transmission Costing Study – An Independent Report Endorsed by the Institution of Engineering & Technology" by Parsons Brinckerhoff in association with Cable Consulting International. Page 10 refers to Double circuit capacities. **http://www.theiet.org/factfiles/transmission-report.cfm**

- net present value ("NPV") of costs that are expected to be incurred during the lifetime of these new transmission assets.

Capital Cost Estimates

D.5 At the initial appraisal stage, National Grid prepares indicative estimates of the capital costs. These indicative estimates are based on the high-level scope of works defined for each Strategic Option in respect of each technology option that is considered to be feasible. As these estimates are prepared before detailed design work has been carried out, National Grid takes account of equivalent assumptions for each option. Final project costs for any solution taken forward following detailed design and risk mitigation will be in excess of any high-level appraisal cost. However, all options would incur these increases in the development of a detailed solution.

D.6 This section considers the capital costs in two parts, firstly the AC technology costs are discussed, followed by HVDC technologies. Each of these technologies is described in Appendix C in more detail.

AC Technology Capital Cost Estimates

D.7 Table D.1 shows the category sizes that are relevant for AC technology circuit designs:-

Category	Design	Rating
Lo	Two AC circuits of 1,595 MVA	3,190 MVA
Med	Two AC circuits of 3,190 MVA	6,380 MVA
Hi	Two AC circuits of 3,465 MVA	6,930 MVA

Table D.1 – AC Technology Circuit Designs

D.8 Table D.2 provides a summary of technology configuration and capital cost information (in financial year 2020/21 prices) for each of the AC technology options that National Grid considers as part of an appraisal of Strategic Options.

IET, PB/CCI Report short-form label	**Circuit Ratings by Voltage**		**Technology Configuration**			**Capital Costs**		
	275kV AC Technologies	**400kV AC Technologies**	**Overhead Line (OHL)**	**AC Underground Cable (AC Cable)**	**Gas Insulated Line (GIL)**	**Overhead Line (OHL)**	**AC Underground Cable (AC Cable)**	**Gas Insulated Line (GIL)**
	Total rating for two Circuits (2 x rating of each circuit)	**Total rating for two Circuits (2 x rating of each circuit)**	**No. of Conductors Sets "bundles" on each arm/circuit of a pylon**	**No. of Cables per phase**	**No of direct buried GIL tubes per phase**	**Cost for a "double" two circuit pylon route (Cost per circuit, of a double circuit pylon route)**	**Cost for a two circuit AC cable route (Cost per circuit, of a two circuit AC cable route)**	**Cost for a two circuit GIL route (Cost per circuit, of a two circuit GIL route)**
Lo	3190MVA (2 x 1595MVA) [2000MVA 2 x 1000MVA for AC Cable only]	3190MVA (2 x 1595MVA)	2 conductor sets per circuit (6 conductors per circuit)	1 Cable per Phase (3 cables per circuit)	1 tube per phase (3 standard GIL tubes per circuit)	£2.88m/km (1.44m/km)	£14.64m/km (£7.32m/km)	£24.62m/km (£12.31m/km)
Med	N/A [3190MVA 2 x 1595MVA for AC Cable only]	6380MVA (2 x 3190MVA)	2 conductor sets per circuit (6 conductors per circuit)	2 Cables per Phase (6 cables per circuit)	1 tube per phase (3 "developing" new large GIL tubes per circuit)	£3.16m/km (£1.58m/km)	£26.96m/km (£13.48m/km)	£28.56m/km (£14.28m/km)
Hi	N/A	6930MVA (2 x 3465MVA)	3 conductor sets per circuit (9 conductors per circuit)	3 Cables per Phase (9 cables per circuit)	2 tubes per phase (6 standard GIL tubes per circuit)	£3.44m/km (£1.72m/km)	£32.46m/km (16.23m/km)	£39.7m/km (£19.85m/km)

Table D.2 - AC Technology Configuration and National Grid Capital Costs by Rating

Notes: -

1. Capital Costs for all technologies are based upon rural/arable land installation with no major obstacles (examples of major obstacles would be Roads, Rivers, Railways etc…)
2. All underground AC Cable and GIL technology costs are for direct buried installations only. AC cable and GIL Tunnel installations would have a higher capital installation cost than direct buried rural installations. However, AC cable or GIL replacement costs following the end of conductor life would benefit from re-use of the tunnel infrastructure.
3. AC cable installation costs exclude the cost of reactors and mid point switching stations, which are described later in this appendix.
4. 275kV circuits will often require Super-Grid Transformers (SGT) to allow connection into the 400kV system, SGT capital costs are not included above but described later in this appendix.
5. 275kV AC cable installations above 1000MVA, as indicated in the table above, would require 2 cables per phase to be installed to achieve ratings of 1595MVA per circuit at 275kV.

D.9 Table D.2 provides a summary of the capital costs associated with the key[31] components of transmission circuits for each technology option. Additional equipment is required for technology configurations that include new:

- AC underground cable circuits
- Connections between 400 kV and 275 kV parts of the Transmission System.

D.10 The following sections provide an overview of the additional requirements associated with each of these technology options and indicative capital costs of additional equipment.

AC Underground Cable additional equipment

D.11 Appendix C of this Report provides a summary of the electrical characteristics of AC underground cable systems and explains that reactive gain occurs on AC underground cables.

D.12 Table D.3 provides a summary of the typical reactive gain within AC underground cable circuits forming part of the Transmission System.

Category	Voltage	Design	Reactive Gain per circuit
Lo	275 kV	One 2500 mm^2 cable per phase	5 Mvar/km
Med	275 kV	Two 2500 mm^2 cable per phase	10 Mvar/km
Lo	400 kV	One 2500 mm^2 cable per phase	10 Mvar/km
Med	400 kV	Two 2500 mm^2 cable per phase	20 Mvar/km
Hi	400 kV	Three 2500 mm^2 cable per phase	30 Mvar/km

Table D.3 – Reactive Gain Within AC underground cable circuits

[31] Components that are not required for all technology options are presented separately in this Appendix.

D.13 National Grid is required to ensure that reactive gain on any circuit that forms part of the Transmission System does not exceed 225 Mvar. Above this limit, reactive gain would lead to unacceptable voltages (voltage requirements as defined in the NETS SQSS). In order to manage reactive gain and therefore voltages, reactors are installed on AC underground cable circuits to ensure that reactive gain in total is less than 225 Mvar.

D.14 For example a 50 km "Med" double circuit would have an overall reactive gain of 1000 Mvar per circuit (2000 Mvar in total for two circuits). The standard shunt reactor size installed at 400 kV on the National Grid System is 200 MVAr. Therefore four 200 Mvar reactors (800 Mvar) need to be installed on each circuit or eight 200 Mvar reactors (1600 Mvar) reactors for the two circuits. Each of these reactors cost £3m adding £24m to an overall cable cost for the example double circuit above.

D.15 Mid point switching stations may be required as part of a design to meet the reactive compensation requirements for AC underground cable circuit. The need for switching stations is dependent upon cable design, location and requirements which cannot be fully defined without detailed design.

D.16 For the purposes of economic appraisal of Strategic Options, National Grid includes a cost allowance that reflects typical requirements for switching stations. These allowances shown in table D.4 are:-

Category	Switching Station Requirement
Lo	Reactive Switching Station every 60km between substations
Med	Reactive Switching Station every 30km between substations
Hi	Reactive Switching Station every 20km between substations

Table D.4 – Reactive Gain Within AC underground cable circuits

D.17 It is noted that more detailed design of AC underground cable systems may require a switching station after a shorter or longer distance than the typical values used by National Grid at the initial appraisal stage.

D.18 Table D.5 below shows the capital cost associated with AC underground cable additional equipment.

Category	Cost per mid point switching station	Cost per 200 Mvar reactor
Lo	£14.3m	£4.7m per reactor
Med	£17.5m	
Hi	£17.5m	

Table D.5 – Additional costs associated with AC underground cables

Connections between AC 275 kV and 400 kV circuits additional equipment

D.19 Equipment that transform voltages between 275kV and 400kV (a 400/275 kV supergrid transformer or "SGT") is required for any new 275 kV circuit that connects to a 400 kV part of the Transmission System (and vice versa). The number of supergrid transformers needed is dependent on the capacity of the new circuit. National Grid can estimate the number of SGTs required as part of an indicative scope of works that is used for the initial appraisal of Strategic Options.

D.20 Table D.6 below shows capital cost associated with the SGT requirements.

275kV Equipment	Capital Cost (SGT - including civil engineering work)
400/275kV SGT 1100MVA (excluding switchgear)	£5.35m per SGT

Table D.6 – Additional costs associated with 275kV circuits requiring connection to the 400kV system

High Voltage Direct Current ("HVDC") Capital Cost Estimates

D.21 Conventional HVDC technology sizes are not easily translated into the "Lo", "Med" and "Hi" ratings suggested in the IET, PB/CCI report. Whilst National Grid information for HVDC is presented for each of these categories, there are differences in the circuit capacity levels. As part of an initial appraisal, National Grid's assessment is based on a standard 2GW converter size. Higher ratings are achievable using multiple circuits.

D.22 The capital costs of HVDC installations can be much higher than for equivalent AC overhead line transmission routes. Each individual HVDC link, between each converter station, requires its own dedicated set of HVDC cables. HVDC may be more economic than equivalent AC overhead lines where the route length is many hundreds of kilometres.

D.23 Table D.7 provides a summary of technology configuration and capital cost information (in financial year 2010/11 prices) for each of the HVDC technology options that National Grid considers as part of an appraisal of Strategic Options.

HVDC Converter Type	2 GW Total HVDC Link Converter Costs (Converter Cost at Each End)	2GW DC Cable Pair Cost
Current Source Technology or "Classic" HVDC	£434m HVDC link cost (£217m at each end)	£2.63m/km
Voltage Source Technology HVDC	£446m HVDC link cost (£223m at each end)	£2.63m/km

Table D.7 - HVDC Technology Capital Costs for 2GW installations

Notes: -

1. Sometimes a different HVDC capacity (different from the required AC capacity) can be utilised for a project due to the different way HVDC technology can control power flow. The capacity requirements for HVDC circuits will be specified in any option considering HVDC. The cost shall be based upon table C.4 above.
3. Where a single HVDC Link is proposed as an option, to maintain compliance with the NETS SQSS, there may be a requirement to install an additional "Earth Return" DC cable. For example a 2GW Link must be capable of operating at ½ its capacity i.e. 1GW during maintenance or following a cable fault. To allow this operation the additional cable known as an "Earth Return" must be installed, this increases cable costs by a further 50% to £3.5m/km.
4. Capital Costs for HVDC cable installations are based upon subsea or rural/arable land installation with no major obstacles (examples of major obstacles would be Subsea Pipelines, Roads, Rivers, Railways etc…)

D.24 Costs can be adjusted from this table to achieve equivalent circuit ratings where required. For example a "Lo" rating 3190 MW would require two HVDC links of (1.6 GW capacity each), while "Med" and "Hi" rating 6380 MW-6930 MW would require three links with technology stretch of (2.1-2.3 GW each).

D.25 Converter costs at each end can also be adjusted, by Linear scaling, from the cost information in Table D.7, to reflect the size of the HVDC link being appraised. HVDC Cable costs are normally left unaltered, as operating at the higher load does not have a large impact the cable costs per km.

D.26 The capacity of HVDC circuits assessed for this Report is not always exactly equivalent to capacity of AC circuits assessed. However, Table D.8 below illustrates how comparisons may be drawn using scaling methodology outlined above.

IET, PB/CCI Report short-form label	Converter Requirements (Circuit Rating)	Total Cable Costs/km (Cable Cost per link)	CSC "Classic" HVDC Total Converter Capital Cost (Total Converter cost per end)	VSC HVDC Total Converter Capital Cost (Total Converter cost per end)
Lo	2 x 1.6 GW HVDC Links (3190MW)	£4.78m/km (2 x £2.39/km)	£672m (4 x £168m [4 converters 2 each end])	£752m (4 x £188m [4 converters 2 each end])
Med	3 x 2.1 GW HVDC Links (6380MW)	£7.89m/km (3 x £2.63/km)	£1302m (6 x £217m [6 converters 3 each end])	£1338m (6 x £223m [6 converters 3 each end])
Hi	3 x 2.3 GW HVDC Links (6930MW)	£7.35m/km (3 x £2.45/km)	£1422m (6 x £237m [6 converters 3 each end])	£1476m (6 x £246m [6 converter 3 each end])

Table D.8 – Illustrative example using scaled 2GW HVDC costs to match equivalent AC ratings (only required where HVDC requirements match AC technology circuit capacity requirements)

Notes: -
1. Costs based on 2GW costs shown in table C.4 and table shows how HVDC costs are estimated based upon HVDC capacity required for each option.
2. Scaling can be used to estimate costs for any size of HVDC link required.

Indication of Technology end of design life replacement impact

D.27 It is unusual for a part of the Transmission System to be decommissioned and the site reinstated. In general, assets will be replaced towards the end of the assets design life. Typically, transmission assets will be decommissioned and removed only as part of an upgrade or replacement by different assets.

D.28 National Grid does not take account of replacement costs in the lifetime cost assessment.

D.29 National Grid's asset replacement decisions take account of actual asset condition. This may lead to actual life of any technology being longer or shorter than the design life, depending on the environment it is installed in, lifetime loading, equipment family failures among other factors for example.

D.30 The following provides a high level summary of common replacement requirements applicable to specific technology options.

a) OHL - Based on the design life of component parts, National Grid assumes an initial design life of around 40 years for overhead line circuits. After the initial 40 year life of an overhead line circuit, substantial pylon replacement works would not normally be required. The cost of Pylons is reflected in the initial indicative capital costs, but the cost of replacement at 40 years would not include the pylon cost. As pylons have an 80 year life and can be re-used to carry new replacement conductors. The replacement costs for overhead line circuits at the end of their initial design life are assessed by National Grid as being around 50% of the initial capital cost, through the re-use of pylons.

b) AC underground Cable - At the end of their initial design life, circa 40 years, replacement costs for underground cables are estimated to be equal or potentially slightly greater than the initial capital cost. This is because of works being required to excavate and remove old cables prior to installing new cables in their place in some instances.

c) GIL - At the end of the initial design life, circa 40 years, estimated replacement costs for underground GIL would be equal to or potentially greater than the initial capital cost. This is because of works being required to excavate and remove GIL prior to installing new GIL in their place in some instances.

d) HVDC - It should be noted at the end of the initial design life, circa 40 years, replacement costs for HVDC are significant. This due to the large capital costs for the replacement of converter stations and the cost of replacing underground or subsea DC cables when required.

Net Present Value Cost Estimates

D.31 At the initial appraisal stage, National Grid prepares estimates of the costs that are expected to be incurred during the design lifetime of the new assets. National Grid considers costs associated with:

- Operation and maintenance
- Electrical losses

D.32 For both categories, Net Present Value ("NPV") calculations are carried out using annual cost estimates and a generic percentage discount rate over the design life period associated with the technology option being considered.

D.33 The design life for all technology equipment is outlined in the technology description in Appendix C. The majority of expected design lives are of the order of 40 years, which is used to asses the following NPV cost estimates below.

D.34 In general discount rates used in NPV calculations would be expected to reflect the normal rate of return for the investor. National Grid's current rate of return is 6.25%. However, the Treasury Green Book recommends a rate of 3.5% for the reasons set out below[32]

> *"The discount rate is used to convert all costs and benefits to 'present values', so that they can be compared. The recommended discount rate is 3.5%. Calculating the present value of the differences between the streams of costs and benefits provides the net present value (NPV) of an option. The NPV is the primary criterion for deciding whether government action can be justified."*

D.35 National Grid considered the impact of using the lower Rate of Return (used by UK Government) on lifetime cost of losses assessments for transmission system investment proposals. Using the rate of 3.5% will discount loss costs, at a lower

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[32] http://www.hm-treasury.gov.uk/d/green_book_complete.pdf Paragraph 5.49 on Page 26 recommends a discount rate of 3.5% calculation for NPV is also shown in the foot note of this page.

NPV calculations are carried out using the following equation over the period of consideration.

D*n* =1/(1 + r)*n*

Where Dn = Annual Loss Cost, r = 3.5% and n = 40 years rate than that of 6.25%. This has the overall effect of increasing the 40 year cost of losses giving a more onerous cost of losses for higher loss technologies.

D.36 For the appraisal of Strategic Options, National Grid recognises the value of closer alignment of its NPV calculations with the approach set out by government for critical infrastructure projects.

Annual Operations and Maintenance cost

D.37 The maintenance costs associated with each technology vary significantly depending upon type. Some electrical equipment is maintained regularly to ensure system performance is maintained. More complex equipment like HVDC converters have a significantly higher cost associated with them, due to their high maintenance requirements for replacement parts. Table D.9 shows the cost of maintenance for each technology, which unlike capital and losses is not dependant on capacity.

	Overhead Line (OHL)	**AC Underground Cable (AC Cable)**	**Gas Insulated Line (GIL)**	**High Voltage Direct Current (HVDC)**
Circuit Annual maintenance cost per two circuit km (AC) **(Annual cost per circuit Km [AC])**	£2,660/km (£1,330/km)	£5,644.45/km (£2,822.22/km)	£2,687.83/km (£1,343.92/km)	£134/km Subsea Cables
Associated equipment Annual Maintenance cost per item	N/A	£6,719.58 per reactor £41,661 per switching station	N/A	£1,300,911 per converter station
Additional costs for 275 kV circuits requiring connection to the 400kV system				
275/400 kV SGT 1100 MVA Annual maintenance cost per SGT	£6,719.58 per SGT	£6,719.58 per SGT	£6.719.58 per SGT	N/A

Table D.9 – Annual maintenance costs by Technology

Annual Electrical Losses and Cost

D.38 At a system level annual losses on the National Grid electricity system equate to less the 2% of energy transported. This means that over 98% of the energy entering the transmission system from generators/interconnectors reaches the bulk demand substations where the energy transitions to the distribution system. Electricity transmission voltages are used to reduce losses, as more power can be transported with lower currents at transmission level, giving rise to the very efficient loss level achieved of less than 2%. The calculations below are used to show how this translates to a transmission route.

D.39 Transmission losses occur in all electrical equipment and are related to the operation and design of the equipment. The main losses within a transmission system come from heating losses associated with the resistance of the electrical circuits, often referred to as I^2R losses (the electrical current flowing through the circuit, squared, multiplied by the resistance). As the load (the amount of power each circuit is carrying) increases, the current in the circuit is larger.

D.40 The average load of a transmission circuit which is incorporated into the transmission system is estimated to be 34% (known as a circuit average utilisation). This figure is calculated from the analysis of the load on each circuit forming part of National Grid's transmission system over the course of a year. This takes account of varying generation and demand conditions and is an appropriate assumption for the majority of Strategic Options.

D.41 This level of circuit utilisation is required because if a fault occurs there needs to be an alternative route to carry power to prevent wide scale loss of electricity for homes, business, towns and cities. Such events would represent a very small part of a circuit's 40 year life, but this availability of alternative routes is an essential requirement at all times to provide secure electricity supplies to the nation.

D.42 In all AC technologies the power losses are calculated directly from the electrical resistance and impedance properties of each technology and associated equipment. Table D.10 provides a summary of circuit resistance data for each AC technology and capacity options considered in this Report.

IET, PB/CCI Report short-form label	AC Overhead Line Conductor Type (complete single circuit resistance for conductor set)	AC Underground Cable Type (complete single circuit resistance for conductor set)	AC Gas Insulated Line (GIL) Type (complete single circuit resistance for conductor set)
Lo	2 x 570 mm^2 (0.025 Ω/km)	1 x 2500 mm^2 (0.013 Ω/km*)	Single Tube per phase (0.0086 Ω/km)
Med	2 x 850 mm^2 (0.0184 Ω/km)	2 x 2500 mm^2 (0.0065 Ω/km*)	Single Tube per phase (0.0086 Ω/km)
Hi	3 x 700 mm^2 (0.014 Ω/km)	3 x 2500 mm^2 (0.0043 Ω/km*)	Two tubes per phase (0.0065 Ω/km)
Losses per 200Mvar Reactor required for AC underground cables			
Reactor Losses	N/A	0.4MW per reactor	N/A
Additional losses for 275kV circuits requiring connection to the 400 kV system			
275 kV options only **275/400 kV SGT losses**	0.2576 Ω (plus 83 kW of iron losses) per SGT	0.2576 Ω (plus 83 kW of iron losses) per SGT	0.2576 Ω (plus 83 kW of iron losses) per SGT

Table D.10 – AC circuit technologies and associated resistance per circuit.

D.43 The process of converting AC power to DC is not 100% efficient. Power losses occur in all elements of the converter station: the valves, transformers, reactive compensation/filtering and auxiliary plant. Manufacturers typically represent these losses in the form of an overall percentage. Table D.11 below shows the typical percentage losses encountered in the conversion process, ignoring losses in the DC cable circuits themselves.

HVDC Converter Type	2 GW Converter Station losses	2GW DC Cable Pair Losses	2GW Total Link loss
Current Source (CSC) Technology or "Classic" HVDC	0.5% per converter	Ignored	1% per HVDC Link
Voltage Source (VSC) Technology HVDC	1.0% per converter	Ignored	2% per HVDC Link

Table D.11 – HVDC circuit technologies and associated resistance per circuit.

D.44 The example calculation explained in detail below is for "Med" category circuits and has been selected to demonstrate the principles of the mathematics set out in this section. This example does not describe specific options set out within this report. A detailed example explanation of the calculations used to calculate AC losses is included in Appendix E.

D.45 The circuit category, for options contained within this report, is set out within each option. The example below demonstrates the mathematics and principles, which is equally applicable to "Lo", "Med" and "Hi" category circuits, over any distance.

D.46 The example calculations (using calculation methodology described in Appendix E) of instantaneous losses for each technology option for an example circuit of 40 km "Med" capacity 6380 MVA (two x 3190 MVA).

- Overhead Lines = (2 x 3) x 1565.5 A^2 x (40 x 0.0184 Ω/km) = 10.8 MW
- Underground Cable = (2 x 3) x1565.5 A^2 x (40 x 0.0065 Ω/km) + (6 x 0.4MW) = 6.2 MW
- Gas Insulated Lines = (2 x 3) x 1565.5 A^2 x (40 x 0.0086 Ω/km) = 5.1 MW
- CSC HVDC = 34% x 6380 MW x 1% = 21.7 MW
- VSC HVDC = 34% x 6380 MW x 2% = 43.4 MW

D.47 An annual loss figure can be calculated from the instantaneous loss. National Grid multiplies the instantaneous loss figure by the number of hours in a year and also by the cost of energy. National Grid uses £60/MWhr.

D.48 The following is a summary of National Grid's example calculations of Annual Losses and Maintenance costs for each technology option for an example circuit of 40 km "Med" capacity 6380 MVA (two x 3190 MVA).

(a) Overhead Line annual loss = 10.8 MW x 24 x 365 x £60/MWhr = £5.7m.

(b) U-ground Cable annual loss = 6.2 MW x 24 x 365 x £60/MWhr = £3.3m.

(c) Gas Insulated lines annual loss = 5.1 MW x 24 x 365 x £60/MWhr = £2.7m

(d) CSC HVDC annual loss = 21.7 MW x 24 x 365 x £60/MWhr = £11.4m

(e) VSC HVDC annual loss = 43.4 MW x 24 x 365 x £60/MWhr = £22.8m

Example Lifetime costs and NPV Cost Estimate

D.49 The annual Operation, Maintenance and loss information is assessed against the NPV model at 3.5% over 40 years and added to the capital costs to provide a lifetime cost for each technology.

D.50 Table D.12 shows an example for a "Med" capacity route 6380 MVA (2 x 3190 MVA) 400 kV, 40km in length over 40 years.

Example 400 kV "Med" Capacity over 40km	**Overhead Line (OHL)**	**AC Underground Cable (AC Cable)**	**Gas Insulated Line (GIL)**	**CSC High Voltage Direct Current (HVDC)**	**VSC High Voltage Direct Current (HVDC)**
Capital Cost	£126.0m	£1178.8m	£1,078.6m	£1,619.1m	£1,650.6m
NPV Loss Cost over 40 years at 3.5% discount rate	£125m	£62.6m	£58.4m	£235.6m	£471.2m
NPV Maintenance Cost over 40 years at 3.5% discount rate	£2.34m	£6.41m	£2.36m	£524.74m	£524.74m
Lifetime Cost	**£253m**	**£1,248m**	**£1,139m**	**£2,379m**	**£2,647m**

Table D.12 – Example Lifetime Cost table (rounded to the nearest £m)

Appendix E – Mathematical Principles used for AC Loss Calculation

E.1 This Appendix provides a detailed description of the mathematical formulae and principles that National Grid applies when calculating losses on the Transmission System. The calculations use recognised mathematical equations which can be found in power system analysis text books.

E.2 The example calculation explained in detail below is for “Med” category circuits and has been selected to demonstrate the principles of the mathematics set out in this section. This example does not describe specific options set out within this report.

E.3 The circuit category, for options contained within this report, is set out within each option. The example below demonstrates the mathematics and principles, which is equally applicable to “Lo”, “Med” and “Hi” category circuits, over any distance.

Example Loss Calculation (1) – 40 km 400 kV “Med” Category Circuits

E.4 The following is an example loss calculation for a 40 km 400 kV “Med” category (capacity of 6,380 MVA made up of two 3,190 MVA circuits).

E.5 Firstly the current flowing in each of the two circuits is calculated from the three phase power equation of $P = \sqrt{3} V_{LL} I_{LL} \cos \theta$. Assuming a unity power factor ($\cos \theta = 1$), the current in each circuit can be calculated using a rearranged form of the three phase power equation of:

(In a star (Y) configuration electrical system $I = I_{LL} = I_{LN}$)

$$I = P/\sqrt{3}V_{LL}$$

Where, P is the circuit utilisation power, which is 34% of circuit rating as set out in D.40 of Appendix D, which for the each of the two circuits in the “Med” category example is calculated as:

$$P = 34\% \times 3190 \text{ MVA} = 1{,}084.6 \text{ MVA}$$

And, V_{LL} is the line to line voltage which for this example is 400 kV.

For this example, the average current flowing in each of the two circuits is

$$I = 1{,}084.6 \times 10^6/(\sqrt{3} \times 400 \times 10^3) = 1{,}565.5 \text{ Amps}$$

E.6 The current calculated above will flow in each of the phases of the three phase circuit. Therefore from this value it is possible to calculate the instantaneous loss which occurs at the 34% utilisation loading factor against circuit rating for any AC technology.

E.7 For this "Med" category example, the total resistance for each technology option is calculated (from information in Appendix D, Table D.10) as follows:

Overhead Line = 0.0184Ω/km x 40 km = 0.736 Ω

Cable Circuit[34] = 0.0065Ω/km x 40 km = 0.26 Ω

Gas Insulated Line = 0.0086Ω/km x 40 km = 0.344 Ω

These circuit resistance values are the total resistance seen in each phase of that particular technology taking account the number of conductors needed for each technology option.

E.8 The following is a total instantaneous loss calculation for the underground cable technology option for the "Med" category example:

Losses per phase are calculated using $P=I^2R$

$$1{,}565.5^2 \times 0.26 = 0.64 \text{ MW}$$

Losses per circuit are calculated using $P=3I^2R$

$$3 \times 1{,}565.5^2 \times 0.26 = 1.91 \text{ MW}$$

Losses for "Med" category are calculated by multiplying losses per circuit by number of circuits in the category

[34] A 40 km three phase underground cable circuit will also require three reactors to ensure that reactive gain is managed within required limits.

$$2 \times 1.91 \text{ MW} = 3.8 \text{ MW}$$

E.9 For underground cable circuits, three reactors per circuit are required (six in total for the two circuits in the "Med" category). Each of these reactors has a loss of 0.4 MW. The total instantaneous losses for this "Med" category example with the underground cable technology option are assessed as:

$$3.8 + (6 \times 0.4) = 6.2 \text{ MW}$$

E.10 The same methodology is applied for the other AC technology option types for the "Med" category example considered in this Appendix. The following is a summary of the instantaneous total losses that were assessed for each technology option:

$$\text{Overhead Lines} = (2 \times 3) \times 1{,}565.5^2 \times 0.736 = 10.8 \text{ MW}$$

$$\text{Cables} = (2 \times 3) \times 1{,}565.5^2 \times 0.26 + (6 \times 0.4) = 6.2 \text{ MW}$$

$$\text{Gas Insulated Lines} = (2 \times 3) \times 1{,}565.5^2 \times 0.344 = 5.1 \text{ MW}$$

Example Loss Calculation (2) – 40 km 275 kV "Lo" Category Circuits Connecting to a 400 kV part of the Transmission System.

E.11 The following is an example loss calculation for a 40 km 275 kV "Lo" category (capacity of 3,190 MVA made up of two 1,595 MVA circuits) and includes details of how losses of the supergrid transformer ("SGT") connections to 400 kV circuits are assessed. This example assesses the losses associated with the GIL technology option up to a connection point to the 400 kV system.

The circuit utilisation power (P) which for the each of the two circuits in the "Lo" category example is calculated as:

$$P = 34\% \times 1{,}595 = 542.3 \text{ MVA}$$

For this example, the average current flowing in each of the two circuits is:

$$I = 542.3 \times 10^6 / (\sqrt{3} \times 275 \times 10^3) = 1{,}138.5 \text{ Amps}$$

E.12 For this "Lo" category example, the total resistance for the GIL technology option is calculated (from information in Appendix D, Table D.10) as follows:

$$0.0086\Omega/\text{km} \times 40 \text{ km} = 0.344\ \Omega$$

E.13 The following is a total instantaneous loss calculation for the GIL technology option for this "Lo" category example:

Losses per circuit are calculated using $P=3I^2R$

$$3 \times 1138.5 \times 0.344 = 1.35 \text{ MW}$$

Losses for "Lo" category 275 kV circuits are calculated by multiplying losses per circuit by number of circuits in the category

$$2 \times 1.35 \text{ MW} = 2.7 \text{ MW}$$

E.14 SGT losses also need to be included as part of the assessment for this "Lo" category example which includes connection to 400 kV circuits. SGT resistance[35] is calculated (from information in Appendix D, Table D.10) as 0.2576 Ω.

E.15 The following is a total instantaneous loss calculation for the SGT connection part of this "Lo" category example:

The average current flowing in each of the two SGT 400 kV winding are calculated as:

$$I_{HV} = 542.3 \times 10^6/(\sqrt{3} \times 400\times10^3) = 782.7 \text{ Amps}$$

Losses per SGT are calculated using $P=3I^2R$

$$\text{SGT Loss} = 3 \times 782.7 \times 0.2576 = 0.475 \text{ MW}$$

Iron Losses in each SGT = 84kW

[35] Resistance value referred to the 400 kV side of the transformer.

Total SGT instantaneous loss (one SGT per GIL circuit) = (2 x 0.475) + (2 x 0.084) = 1.1 MW

E.16 For this example, the total "Lo" category loss is the sum of the calculated GIL and SGT total loss figures:

"Lo" category loss = 2.7 + 1.1 = 3.8 MW