RIIO-ED1 RIGs Environment and Innovation Commentary, version 7.0

2022/23

Scottish and Southern Electricity Networks (SSEN)

Contents

Summary – Information Required

One Commentary document is required per DNO Group. Respondents should ensure that comments are clearly marked to show whether they relate to all the DNOs in the group or to which DNO they relate.

Commentary is required in response to specific questions included in this document. DNO's may include supporting documentation where they consider it necessary to support their comments or where it may aid Ofgem's understanding. Please highlight in this document if additional information is provided.

The purpose of this commentary is to provide the opportunity for DNOs to set out further supporting information related to the data provided in the Environment and Innovation Reporting Pack. It also sets out supporting data submissions that DNOs must provide to us.

Worksheet by worksheet commentary

At a worksheet by worksheet level there is one standard question to address, where appropriate, as follows:

- **Allocation and estimation methodologies**: DNOs should detail estimates, allocations or apportionments used in reaching the numbers submitted in the worksheets.

  This is required for all individual worksheets (ie not an aggregate level), where relevant. Not all tables will have used allocation or estimation methods to reach the numbers. Where this is the case simply note "NA".

  Note: this concerns the methodology and assumptions and not about the systems in place to check their accuracy (that is for the NetDAR). This need to be completed for all worksheets, where an allocation or estimation technique was used.

In addition to the standard commentary questions, some questions specific to each worksheet are asked.

E1 – Visual Amenity

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
SSEH and SSES Project costs have been allocated on a project-by-project basis. The total expenditure for these projects has been allocated based upon the appropriate activity driver with no apportionment or estimations.

Explanation of the increase or decrease in the total length of OHL inside designated areas for reasons other than those recorded in worksheet E1. For example, due to the expansion of an existing, or creation of a new, Designated Area.
SSEH 21.47km of Overhead line was removed from Cairngorm National Park during a cleansing activity that identified duplicated OH line in our system. 12.69km of Overhead line was removed from The Cairngorm Mountain National Scenic Area during the same cleansing activity. **SSES** Circuit reinforcement work in Sussex Downs AONB resulted in the removal of 4.12km of EHV OHL.

E2 – Environmental Reporting

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
SSEH & SSES Project costs have been allocated on a project-by-project basis. Total expenditure for projects is allocated to the appropriate investment driver, identifiable down to the individual cell level in the E2 table. **Data obtained from our Asset Management Systems** The following information provided in the table has been taken from our asset management system (Maximo): • Fluid used to top-up cables • SF6 Bank • SF6 Emitted The Fluid Filled cables in service is taken from Electric Office (EO), and the Oil in service is calculated from this figure, using the following conversion rates: • 481l of oil per km for 33kV cables • 871l of oil per km for 66kV cables • 871l of oil per km for 132kV cables

We do not currently have a process to capture the volume of fluid recovered from fluid filled cables.

Activity volumes have been derived from the actual projects completed during 2022/23.

DNOs must provide some analysis of any emerging trends in the environmental data and any areas of trade-off in performance.
For both SSEH and SSES there is a significant trend since 2018/2019 of decreasing the volume of fluid used to top up cables. This is largely due to work in 2018/19 to update processes surrounding collection of data resulting in more cables being tagged. Data helped identify circuits requiring replacement and targeted intervention. SF6 emitted has increased in both licence areas in 2022/23 due to poorer leak performance. This follows two years of decreases in2020/21 and 2021/22. Work began in 2020/21 to remove assets with Persistent Organic Pollutants. It involved a large volume of data collection and testing. In 2020/21 there was removal of 24 assets in SSEH, in 2021/22 there was a removal of 159 assets in SSEH and 34 in SSES. Now in 2022/23 there was a removal of 1048 assets in SSEH and 434 in SSES.

Where reported in the Regulatory Year under report, DNOs must provide discussion of the nature of any complaints relating to Noise Pollution and the nature of associated measures undertaken to resolve them.
SSEH & SSES Noise complaints in 2022/23 for both SSEH and SSES included complaints relating to substation noise or noise from transformers. There was 1 complaint in our SSEH licence area and 8 in SSES. In SSES there has been progress on 2 Noise Pollution schemes with £165k spend that will complete in 2023/24. These works include building a noise reduction barrier and replacing a transformer with a new low noise transformer.

Where reported in the Regulatory Year under report, DNOs must provide details of any Non-Undergrounding Visual Amenity Schemes undertaken.
SSEH & SSES No Non-Undergrounding Visual Amenity Schemes were undertaken.

Any Undergrounding for Visual Amenity should be identified including details of the activity location, including whether it falls within a Designated Area.
SSEH & SSES There is no undergrounding within a Designated Area reported in E2. Any undergrounding is reported in Table E1.

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any reportable incidents or prosecutions associated with any of the activities reported in the worksheet.
SSEH N/A **SSES** In 2022/23, there are 37 reportable incidents where fluid filled cable leaks exceeded 40 litres per month. These incidents were reported to Environment Agency.

Where reported in the Regulatory Year under report, DNOs must provide discussion of details of any Environmental Management System (EMS) certified under ISO or other recognised accreditation scheme.
N/A

DNOs must provide a brief description of any permitting, licencing, registrations and permissions, etc related to the activities reported in this worksheet that you have purchased or obtained during the Regulatory Year.
SSEH and SSES Environmental permits were required to store hazardous waste oil which has been removed from our substation plant during routine maintenance. The waste oil is removed by tanker and sent for reprocessing which is part of our oil pollution mitigation activities. The conditions on this permit require a technically competent person to regularly audit our sites to ensure we are compliant.

DNOs must include a description of any SF6 and Oil Pollution Mitigation Schemes undertaken in the Regulatory Year including the cost and benefit implications and how these were assessed.
<u>SSEH</u> **SF6 Emitted Mitigation Schemes** There were no SF6 Mitigation schemes in SSEH in 2022/23 however schemes are due to be delivered in the first year of RIIO-ED2 including schemes at St Cyrus and Inverbervie. 132kV is a Transmission voltage in Scotland so our efforts in ED1 were to target the 132kV assets in SSES. As technology and methodology has improved, we can now focus efforts at lower voltages. **Oil Pollution Mitigation Schemes – Cables, Operational and Non-Operational Sites** There were no Oil Pollution Mitigation Schemes in SSEH in 2022/23 however work on a scheme in Killin is underway in RIIO-ED2. Our FFC population in the North is minimal and our environmental risk posed was less than in the south. **<u>SSES</u>** **SF6 Emitted Mitigation Schemes** Work has started on 3 schemes with a spend of £48k to date, these schemes will replace SF6 insulated circuit breakers.

Oil Pollution Mitigation Schemes – Cables, Operational and Non-Operational Sites Cable tagging was completed at 1 site at a cost of £23k. There was also the completion of two operational schemes where transformer bunds were built at Netley Common Substation and Cholsey Substation to a cost of £111k and £110k respectively.

E3 –BCF

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
Emissions source figures used to calculate the associated estimated emissions submitted for SSEH and SSES have been extracted from a number of sources which include our asset management system Maximo, and our expenses and travel systems. The only area where we have used estimation principles is in calculating the electrical load for substations in both SSEH & SSES areas which are then used to derive the associated estimated emissions. The estimating principle is described in this narrative under Building Energy Usage.

BCF reporting boundary and apportionment factor DNOs that are part of a larger corporate group must provide a brief introduction outlining the structure of the group, detailing which organisations are considered within the reporting boundary for the purpose of BCF reporting. Any apportionment of emissions across a corporate group to the DNO business units must be explained and, where the method for apportionment differs from the method proposed in the worksheet guidance, justified.
<u>**SSEH & SSES**</u> SSEN Distribution is part of the wider corporate group SSE plc. There is no apportionment of emissions across the corporate group. E3 - BCF reporting relates to SSEH and SSES only. However, energy usage within shared buildings is allocated using our Corporate Recharge model which is consistent in all submissions to Ofgem.

BCF process The reporting methodology for BCF must be compliant with the principles of the Greenhouse Gas Protocol.[1] Accounting approaches, inventory boundary and calculation methodology must be applied consistently over time. Where any processes are improved with time, DNOs should provide an explanation and assessment of the potential impact of the changes.
We have followed Ofgem's classification of carbon sources and are compliant with the Greenhouse Gas Protocol. All conversion rates are extracted from specific annexes listed in the UK Government (DEFRA/BEIS) Greenhouse Gas (GHG) conversion factors for company reporting.

[1] Greenhouse gas protocol

The 2022 UK Government GHG Conversion Factors for Company Reporting ("ghg-conversion-factors-2022-full-set" have been used throughout in the calculation of SSEN Distribution's 2022/23 GHG emissions.

Table E3 of the Environment and Innovation pack requires a single GHG factor to be reported for each DNO GHG emission activity. However, in some cases, there are multiple GHG emission conversion factors used for a GHG emission activity (e.g for business air travel there are conversion factors for domestic, international short haul and international long haul, etc). In these instances, and consistent with paragraph 2.33 of Annex J, a weighted average of these factors was used to derive a single GHG conversion factor which was applied to the total volume reported under the category concerned. The process involved applying the conversion factor (from the 2022 BEIS GHG conversion factors) to the volume of each GHG emissions source activity to derive the tCO2-e. The tCO2-e of the individual components are then combined and divided by the total volume of GHG activities to derive a single GHG conversion factor. A single weighted GHG conversion factor is used in Ofgem's table E3 summary table to derive an overall tCO2-e value for the GHG activity concerned.

Commentary required for each category of BCF
For **each** category of BCF in the worksheet (ie Business Energy Usage, Operation Transport etc) DNOs must, where applicable, provide a description of the following information, ideally at the same level of granularity as the Defra conversion factors:

- the methodology used to calculate the values, outlining and explaining any specific assumptions or deviations from the Greenhouse Gas Protocol
- the data source and collection process
- the source of the emission conversion factor (this shall be Defra unless there is a compelling case for using another conversion factor. Justification should be included for any deviation from Defra factors.)
- the Scope of the emissions ie, Scope 1, 2 or 3
- whether the emissions have been measured or estimated and, if estimated the assumptions used and a description of the degree of estimation
- any decisions to exclude any sources of emissions, including any fugitive emissions which have not been calculated or estimated
- any tools used in the calculation
- where multiple conversion factors are required to calculate BCF (eg, due to use of both diesel and petrol vehicles), DNOs should describe their methodology in commentary
- where multiple units are required for calculation of volumes in a given BCF category (eg, a mixture of mileage and fuel volume for transport), DNOs should describe their methodology in commentary, including the relevant physical units, eg miles.

DNOs may provide any other relevant information here on BCF, such as commentary on the change in BCF, and should ensure the baseline year for reference in any description of targets or changes in BCF is the Regulatory Year 2014-15. DNOs should make clear any differences in the commentary that relate to DNO and contractor emissions.

Building Energy Usage (Scope 2)

Buildings – Electricity, Other Fuels
Energy usage (both electricity and gas) within shared buildings is allocated using our Corporate Recharge model which is consistent in all submissions to Ofgem. The annual grid average conversion factor was used to provide the buildings electricity section. The gross calorific value has been applied consistently for the conversion of gas figures.

		Electricity (kWh)	Gas (kWh)	tCO2-e	% Change (tCO2-e)
SSEH	2020/21	1,694,758.70	103,833.00	414.21	-
	2021/22	1,887,499.86	78,204.98	415.1	15.77%
	2022/23	2,392,716.27	97,931.18	480.58	
SSES	2020/21	1,762,914.18	122,007.11	433.44	-
	2021/22	2,491,446.11	156,991.82	557.76	1.08%
	2022/23	2,770,163.78	153,815.06	563.77	

Substation Energy
Substations have been separated into three categories for energy usage estimations:

- HV: 6.6kV – 20kV
- EHV: 22kV – 66kV
- 132kV (SSES only), as 132kV is a Transmission voltage in Scotland

All SSEN Distribution substations are registered as unmetered supplies so in calculating the total BCF, the substation energy consumed - which is calculated from our own estimate framework (detailed below) - is deducted from the total system losses to avoid double counting. A best estimate framework for the energy consumption at these sites has been used. Principles and assumptions used in this estimation are detailed below.

Substation Numbers
The number of substations in each category is taken from our asset management system, Maximo. The numbers are split between our licensees to give figures for both SSEH and SSES. Out of area substations are excluded.

Estimating Principles
Electrical demand in a substation comes from a combination of elements such as space heating, panel heaters, lighting of buildings, battery chargers, mains, transformer coolers & site security equipment (flood lighting, CCTV cameras etc). Between SSEH and SSES, usage described above can vary due to the geographical location and differences in climates.

For substation electricity calculation, we use total numbers of substations at EHV voltage and above multiplied by a factor which is created through the estimated principles to give us an estimated usage. For HV substations however due to the classification of indoor/outdoor categorisation on Maximo, we assume 3.5% of the total of all HV substations have the equipment mentioned above installed, therefore we multiply this value by a factor which is created through the estimated principles to give us an estimated usage. We believe this gives a more realistic view on the substation electricity usage as we believe not all our indoor substations would use the factors described above. Work is ongoing to align our substation categorisation within Maximo against our other core systems such as EO & PowerOn, to enable us to move away from the 3.5% estimate.
The appropriate 2022 BEIS conversion factor has been used to convert the kWh of electricity used into tonnes of carbon dioxide equivalent (tCO2-e).

<u>Operational Transport</u> (Scope 1)

Road
The volume of fuel (litres) consumed by operational vehicles is captured using fuel cards and is reported separately for SSEH and SSES. We do not report freight separately from passenger operational transport, so all operational travel has been reported under passenger transport.
The appropriate 2022 BEIS conversion factor has been used to convert the volume of fuel consumed into tCO2-e.

The volume figures are shown below:

		Petrol (litres)	Diesel (litres)	Gas Oil (litres)	LPG (litres)	tCO2-e	% Change (tCO2-e)
SSEH	2021/22	28,184.46	1,629,550.08	189,265.33	299	4,678.36	-11.89%
	2022/23	27,189.24	1,588,641.90	0.00	-	4,122.27	
SSES	2021/22	12,898.72	2,564,227.48	441,075.99	-	7,687.22	-14.43%
	2022/23	16,835.28	2,557,334.47	-	-	6,577.65	
TOTAL	2021/22	41,083.18	4,193,777.56	630,341.32	299	12,365.58	-13.47%
	2022/23	44,024.52	4,145,976.37	-	-	10,699.92	

In 2022/23 there was no gas oil or LPG associated with Road Operational Transport given these fuel sources were used for Fuel Combustion of plant, therefore the litres used for gas oil and LPG are attributed to Fuel Combustion.

Rail
Any operational rail journeys have been included in the business travel section of the report.

Sea
Any operational sea journeys have been included in the business travel section of the report.

Air
Helicopters are used to monitor our network, especially during storms to assess network damage. The use of helicopters to monitor our network and assess damage is essential in ensuring continuity and security of supply.
Actual litres of aviation fuel consumed during hours flown in both SSEH and SSES was provided by the contractor and used in conjunction with the 2022 BEIS GHG conversion factor to determine associated tCO2-e.

The air operational transport figures are shown below:

	2021/22		2022/23		
	Litres	tCO2-e	Litres	tCO2-e	% Change (tCO2-e)
SSEH	52,080.00	121.37	36,200.00	92.13	-24.09%
SSES	62,475.00	145.60	51,325.00	130.63	-10.28%

The decreased winter storm activity seen during 2022/23 has resulted in fewer GHG emissions than the previous reporting year.

<u>Business Transport</u> (Scope 3)

Road
Business transport miles are captured through our finance department. The distance travelled by both petrol and diesel vehicles are used to calculate the associated GHG emissions.

Rail & Sea
Journeys made for business travel by rail and sea are recorded through our travel department. The distance travelled is used to calculate the associated GHG emissions.

Air
Emissions for business travel by air are recorded through our travel department. Class of travel is not recorded. All flights taken between UK locations have been reported as domestic, flights from the UK to Europe as Short-Haul International, and flights from the UK to non-European destinations as Long Haul International. Internal flights in countries other than the UK have been reported as domestic flights.

		Road (miles)	Rail (km)	Sea (km)	Air (km)	tCO2-e	% Change (tCO2-e)
SSEH	2021/22	862,963.00	132,354.18	59,974.29	320,802.76	283.41	47.72 %

	2022/23	1,096,643.00	364,589.00	126,404.00	874,120.00	418.66	
SSES	2021/22	2,344,234.00	195,172.21	1,947.00	105,257.60	637.40	1.30%
	2022/23	2,420,263.00	431,014.00	10,088.00	295,794.00	645.67	
TOTAL	2021/22	3,207,197.00	327,526.39	61,921.29	426,060.36	920.81	15.59%
	2022/23	3,516,906.00	795,603.00	136,492.00	1,169,914.00	1064.33	

In both SSEH and SSES, historical emissions associated with business transport are reflective of the impact of the Covid-19 pandemic and our compliance with UK and Scottish governments rules and guidance during 'lockdowns' and restrictions of travel and our response. Our implementation of covid-safe working practices and enabling technology allowed our employees to conduct business and work remotely, and from home, which reduced business travel for most of the year unless it was deemed essential or necessary. As Covid-19 restrictions eased, and activities in our island and rural communities (such as project work, operation and maintenance, tree cutting, subsea cable, supply restoration) continued, some increases in travel were seen and therefore associated emissions increased, including in 2022/23. However, volumes and associated GHG emissions are still much lower than pre Covid-19 levels.

<u>Fugitive Emissions</u> (Scope 1)

SF_6

Emissions of SF_6 are recorded in our Asset Management System and represent the amount of SF_6 used to top-up assets during fault repair, routine maintenance or commissioning of assets that use SF_6 as an insulating medium. The appropriate 2022 BEIS GHG conversion factor was used to calculate the associated GHG emissions in tCO2-e.

	2021/22		2022/23		
	SF_6 (kg)	tCO2-e	SF_6 (kg)	tCO2-e	% Change (tCO2-e)
SSEH	0.78	17.78	3.85	87.78	393.70%
SSES	155.48	3,545.04	202.71	4,621.79	30.37%

The 3.85kg of SF_6 emitted in SSEH and 202.71kg emitted in SSES during 2022/23 was due to natural leakage and subsequentially required top-ups as part of normal maintenance and prolongued cold snaps experienced that exacerbated leaks. To counter this, improved monitoring and analysis have been developed to track the poorest performing assets and SSEN Distribution have begun targeting investment to replace these where repair is not suitable. Limited market availability of SF6 alternatives has also restricted opportunities to reduce our SF6 bank. SSEN Distribution have also been working collaboratively with other TNOs and DNOs via the ENA to establish our position to gradually phase out the SF6 assets with alternatives in line with the proposed regulation, Regulation (EU) No 517/2014.
In addition, SSEN Distribution has successfully implemented the business process to seamlessly initiate the asset replacement or intervention via CNAIM trigger in line with SSEN Distribution's asset classes approach.

<u>Fuel Combustion</u> (Scope 1)

We record the volume of fuel used to provide back up generation on our distribution networks.

Mobile Generation
Mobile generation is primarily required as backup to ensure continuity and security of supply when works requiring a network outage are taking place, or to provide temporary restoration of supplies to customers during a severe weather event. Gas oil (also known as red diesel) has been historically used in some regions, however, white diesel has been used in place of gas oil from March 2022 due to a change in regulation.
The appropriate 2022 BEIS GHG conversion factor was used to calculate the associated GHG emissions in tCO2-e.

		Diesel (litres)	Gas Oil (litres)	Petrol (litres)	tCO2-e	% Change (tCO2-e)
SSEH	2021/22	65,272.40	1,552,330.36	134.12	4,446.56	2.50%
	2022/23	1,622,987.41	147,105.24	182.97	4,557.54	
SSES	2021/22	297,562.82	5,580,669.05	-	16,209.15	-0.74%
	2022/23	3,896,682.63	2,219,301.64	-	16,089.19	
TOTAL	2021/22	362,835.22	7,132,999.41	134.12	20,655.71	-0.04%
	2022/23	5,519,670.04	2,366,406.88	182.97	20,646.73	

Despite an increase in the 2022 BEIS conversion factor figures, usage was reduced compared to 2021/22 due to reduced storm activity in 2022/23.

Fixed Generation (Diesel)
Our fixed (embedded) generation is primarily required as a backup in the event of network faults to ensure security of supply to our islanded communities. Our 7 power stations are located on the islands off the North of Scotland. No fixed generation sites are located in the SSES license area.
The appropriate 2022 BEIS GHG conversion factor was used to calculate the associated GHG emissions in tCO2-e.

		Gas Oil (litres)	tCO2-e	% Change (tCO2-e)
SSEH	2021/22	12,570,970.00	34,677.83	-93.54%
	2022/23	811,469.00	2,238.49	

The gas oil used during 2022/23 was utilised at our embedded generation stations operated to maintain continuity and security of supply for customers in our island communities during power outages caused by planned or unplanned works, including storms. The drastic reduction in GHG emissions from 2021/22 is due to the subsea cable faults being restored in 2021/22 and reduced storm activity experienced during 2022/23.

<u>Losses</u> (Scope 3)

Figures for network losses have a two year lag given the industry reconciliation process, however, an estimate is produced at the end of the reporting year and converted to tCO2-e using the appropriate 2022 BEIS conversion factor.

	2021/22		2022/23			
	Losses (kWh)	tCO2-e	Losses (kWh)	tCO2-e	% Change (kWh)	% Change (tCO2-e)
SSEH	523,755,847.13	111,209.08	487,369,070.49	94,247.43	-6.95%	-15.25%
SSES	1,590,400,000.00	337,689.63	1,531,700,000.00	296,200.15	-3.69%	-12.29%

Losses are proportional to the amount of energy that flows through our network, and the emissions associated are a function of the generation mix. In 2022/23, network losses reduced compared to 2021/22 largely due to the cost-of-living crisis which saw reduced load as consumers tried to reduce their electricity consumption. Additionally, the 2022 BEIS conversion factor is lower than the 2021 conversion factor, due to an increased proportion of renewable generation, resulting in a decrease in tCO2-e associated with the losses. The 2021/22 kWh, and therefore associated emissions, were updated following reconciliation in 2022/23.

Contractors

When reporting BCF emissions due to contractors in the second half of the worksheet please:

- Explain, and justify, the exclusion of any contractors and any thresholds used for exclusion.
- Provide an indication of what proportion of contractors have been excluded. This figure could be calculated based on contract value.

Please provide a description of contractors' certified schemes for BCF where a breakdown of the calculation for their submitted values is not provided in the worksheet.

If a DNO's accredited contractor is unable to provide a breakdown of the calculation and has entered a dummy volume unit of '1' in the worksheet please provide details of the applicable accredited certification scheme which applies to the reported values.

Operational Road Transport, Contractors (Scope 3)

BCF emissions due to contractors are reported under operational transport and are related to fuel used in contractor vehicles (not owned by SSEN Distribution) for business activities.

Fuel used in vehicles not owned by SSEN Distribution is calculated based on estimated transport spend from our contractors. This is converted into miles travelled using SSE's mileage rate. The mileage is then converted into kms and then converted into tCO2-e using the appropriate 2022 BEIS conversion factor.

	2021/22		2022/23		
	km	tCO2-e	km	tCO2-e	% Change (tCO2-e)
SSEH	236,018.47	56.92	255,045.05	43.57	-23.46%
SSES	2,118,814.55	510.97	1,571,265.73	268.41	-47.47%
TOTAL	2,354,833.02	567.89	1,826,310.78	311.98	-45.06%

This year, there has been an overall decrease in contractor transport spend due to more efficient contractor arrangements. Additionally, the 2022 BEIS conversion factor was considerably lower compared to the 2021 conversion factor. Efforts to improve this reporting by progressing through the Scope 3 reporting methodology hierarchy is underway for RIIO-ED2 and beyond.

Building energy usage Natural gas, Diesel and other fuels are all categorised as fuel combustion and must be converted to tCO2e on either a Gross Calorific Value (Gross CV) or Net Calorific Value (Net CV) basis. The chosen approach should be explained, including whether it has been adapted over time. Substation Electricity must be captured under Buildings Energy Usage. Please explain the basis on which energy supplied has been assessed.
<u>SSEH and SSES</u> Please refer to the paragraph on Buildings Energy Usage under the section titled "Commentary required for each category of BCF".

E4 – Losses Snapshot

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
<u>SSEH and SSES</u> **LV & 11kV upsizing minimum cables** The bullet points below detail workings used to calculate losses savings from increasing the size of cables. • 2015/16 has been used as the baseline year as the losses policy on minimum upsizing of cables was implemented after this year. • Increase in percentage of cable quantity procured is attributed to losses policy e.g. 92.4% 95sqmm to 7.6% 185sqmm procured in 2015/16 (baseline) vs 89.4% 95sqmm to 10.6% 185sqmm procured in 2016/17 = 2.98% increase in 185 sqmm cable attributed to losses policy. • It is assumed that purchase orders for cables within each regulatory year correspond to installation of cables in year of purchase. • Losses reductions from upsizing minimum cable size have been calculated using actual LV and 11kV demand data along with cable resistance data. This is represented in MWhr figures. Upsizing LV cable from 95sqmm to 185sqmm saves 13.83MWhrs per km per year. Upsizing 11kV cable from 70sqmm to 150sqmm saves 12.37MWhrs per km per year. • Losses reduction figures are divided by two in the first year of implementation. This is because installation of cables occurs throughout the year, half of which occur in the second half of the year. To account for this the final MWhr figure has been divided by two in the first year of implementation only. E.g. In Estimated Distribution Losses benefits over 'Baseline Scenario', for 2016/17 (the first year where larger cables were installed due to the losses policy) the final MWhr figure has been divided by 2. In 2017/18 this figure is no longer divided by 2. This is because all cables have been installed and therefore are reaping full losses benefits, but instead the MWh saving for the cable installed in 2017/18 will be divided by 2. • E4 Volumes figures: Cable volume figures are taken from the cost and volume reporting pack. A percentage modifier has been applied to this so that volumes represent the amount of cable that has been upsized over the baseline scenario. • E4 Estimated total costs: Multiplier figure is calculated as the average cost per km for procuring the larger cable size.

- E4 Estimated Distribution Justified Costs: Multiplier figure is calculated as the difference in cost between procuring the larger cable size vs the smaller cable size. E.g the cost of 185sqmm vs 95sqmm
- E4 Estimated Distribution Losses benefits over 'Baseline Scenario': Multiplier figure is calculated as the MWh losses reduction for installing the larger cable size e.g 185sqmm vs 95sqmm. Losses reductions are cumulative and multiplied up over consecutive years in the price control. This has been estimated based on a typical load profile for both an HV and LV feeder.

SSES
6.6kV to 11kV upgrade
The bullet points below detail workings used to calculate losses savings from upgrading the network from 6.6kV to 11kV.

- Legacy 6.6kV networks in SSES have largely been being upgraded to 11kV. Historically, 6.6kV networks were commonly used but are not appropriate for modern power demands and are gradually being replaced by more modern equipment. The increase in voltage will result in a reduction in current, which will have a positive impact on losses for the same load. The volume of cable replaced is reported by the regions. It is assumed that the upgraded network is operational in the scheduled year of completion and the legacy network is removed.
- As 6.6kV cable has not been widely utilised for many years, it is no longer part of our procurement portfolio. Therefore, the costs have been estimated to be approximately the same as 70sqmm 11kV conductors. This is used to create a cost for the Baseline scenario.
- Losses reductions are attributed to the volume of cable upgraded. This has been calculated at 6.9MWh per km per year based on a typical load profile. This calculation assumes conductor sizes and therefore resistances are similar, but a reduction in current of 40% is achieved from increasing the voltage from 6.6kV to 11kV.
- The losses reduction is halved in the first year of implementation as it is assumed that a scheme becomes operational on average halfway through the year. Subsequent years have the full losses reduction attributed.

SSEH and SSES
Low loss transformers
The bullet points below detail workings used to calculate losses savings gained when replacing 33kV, 66kV and 132kV ground mounted transformers with energy efficient versions that meet the EU Ecodesign Directive Tier 2 standard.

- Volume of transformer installations are taken from the cost & volume reporting pack. The procurement standard when replacing transformers is to ensure Tier 2 Ecodesign standard is met. Therefore, it is assumed that all new installations are to this standard.
- The costs of standard transformers and those that meet Tier 2 specifications have been estimated. The difference between the two is the proportion attributed to the Losses Strategy.
- Tranformer efficiencies at Tier 1 and Tier 2 have been taken from the Minimum Peak Efficiency Index values in the EU Ecodesign Directive. Efficiencies of current installed "baseline" transformers vary depending on the specification of the installation. It is assumed on average that baseline transformers are 0.05% less efficient than Ecodesign Tier 1 minimum requirements, as this is the percentage increase in efficiency between Tier 1 and Tier 2.

- The losses saving between baseline and Tier 2 transformers was calculated using the minimum peak efficiency index on a standard load profile. This ranged from 32.8MWh losses saving per year for each transformer at 33kV up to 84.1MWh saving per year at 132kV.

<u>SSEH and SSES</u>
Pre-1960 transformer replacement
The bullet points below detail workings used to calculate losses savings for replacing pre-1960s transformers with modern equivalents.

- The volume of pre-1960 HV and EHV transformers replaced on the network is determined by comparing the age of transformers one year vs their age the following year. E.g if a transformer was 62 in Apr-2018, then 0 in Apr-2019 it is assumed that the transformer has been replaced with a modern equivalent. If it was 62 in Apr-2018, then 63 in Apr-2019 it is assumed the transformer has not been replaced.
- The losses savings are calculated based on replacing pre-1960 transformers with modern baseline equivalents (not units that meet the Tier 2 specifications for the Ecodesign Directive). It is assumed however that pre-1960 transformers are replaced with units that meet Tier 2 specifications, hence pre-1960 transformer replacements will be counted in both this section AND the "low loss transformers" section above.
- As these transformers are at end of life and being replaced anyway there is no "distribution losses justified cost" associated with the upgrade, as the upgrade is triggered by asset condition rather than being losses driven.
-

<u>SSEH and SSES</u>
Relevant theft of electricity
The bullet points below detail workings used to calculate losses savings for reducing energy theft and unmetered properties.

- Volume of MPAN rectification is based on the number of resolved energy theft (or identification of unmetred property) cases per year. One MPAN = One resolved case. This is broken down further into domestic and non-domestic cases.
- Domestic and Non-Domestic MWhr savings are taken from the Common Distribution Charging Methodology (CDCM) model. Table "1053: Volume forecasts for the charging year" is used to estimate the MWhr savings per MPAN.
- Losses reduction figures are divided by two in first year of implementation. This is because rectification of MPANs occurs throughout the year, half of which occur in the second half of the year. To account for this the final MWhr figure has been divided by two in the first year of rectification only.

Programme/Project Title Please provide a brief summary and rationale for each of the activities in column C which you have reported against.
<u>SSEH and SSES</u> **LV & 11kV upsizing minimum cables** LV cables have been upsized from 95 sqmm to 185 sqmm and 11kV cables have been upsized from 70 sqmm to 150 sqmm specifically to reduce

losses. Upsizing cables is more expensive, but due to the reduced losses over the life span of the cable it makes financial sense as shown in the CBAs.

6.6kV to 11kV upgrade
Historically, SSEN Distribution had some legacy 6.6kV circuits on our network. These have largely been upgraded to 11kV for capacity reasons and to meet current standards. This upgrade delivers a reduction in losses as shown in the CBA.

Low loss transformers
When replacing transformers, we are choosing models that meet the Tier 2 minimum requirements as stated in the EU Ecodesign Directive. These models are slightly more expensive but are more efficient, delivering a loss saving.

Pre-1960 transformer replacements
There are still some pre-1960s transformers on our network. These are recognised to be less efficient than modern equivalents. As these transformers are selected for replacement (based on a condition assessment) we are replacing with models that meet the Tier 2 minimum requirements of the EU Ecodesign Directive.

Relevant theft of electricity
Theft of electricity is a major cause of losses. We have a team within SSEN Distribution that is specifically dedicated to identifying electricity theft to reduce these losses. It is by far the largest activity within SSEN Distribution that contributes to the reduction in losses.

Primary driver of activity
If, in column E, you have selected 'Other' as the primary driver of the activity, please provide further explanation.

SSEH and SSES

Other is selected in LV and 11kV cable technical losses. It is made up of multiple data sources i.e., Connections (V3) and Other Asset Movement (V4), which is not included in the drop-down menu on the E4 table. Since 2019/20 additional cable volumes have been added to the "Other" category. This includes cables procured for Visual Amenity (CV20), Diversions (CV5), OH Clearances (CV18) and Faults (CV26).

Other is selected for Relevant theft of electricity. This is not included in the E4 drop down menu either

Baseline Scenario
Please provide a brief description of the 'Baseline Scenario' inputted in column K for each activity.

SSEH and SSES

LV & 11kV upsizing minimum cables
The baseline scenario used here is based on the previous policy of using smaller standard cable sizes i.e. 95 sqmm cables for LV and 70 sqmm cables for 11kV. These are standard cable sizes that are used in SSEN Distribution.

6.6kV to 11kV upgrade
The baseline scenario here would be to replace the 6.6kV network like for like. Whilst this is not an option (due to the minimum standard now being 11kV),

the baseline scenario is built on 6.6kV for illustrative purposes to show the losses benefit of upgrading to 11kV.

Low loss transformers
The baseline scenario would be replacing transformers like for like, i.e with models that do not meet Tier 2 of the EU Ecodesign Directive.

Pre-1960 transformer replacements
The baseline scenario here would be leaving the inefficient 1960s transformers in place.

Relevant theft of electricity
There is no baseline here as each year electricity theft is discovered we reduce losses. It is therefore not applicable to include a baseline.

Use of the RIIO-ED1 CBA Tool
DNOs should use the latest version of the RIIO-ED1 CBA Tool for each of the activities reported in column C. Where the RIIO-ED1 CBA Tool cannot be used to justify an activity, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report must be submitted.

SSEH and SSES

CBA tool is used for LV and 11kV cables, the 6.6kV to 11kV upgrade and the low loss and pre-1960 transformers.
No CBA exists for relevant theft of electricity as this is settled on the number of MPAN resolutions as detailed in the first section.

Changes to CBAs If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows: • a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, or • a substantively different NPV from that used to justify an activity that has already begun. the DNO should include an explanation of what has changed and why the DNO is continuing the activity. For example, where the carbon price used in the RIIO-ED1 CBA Tool has changed from that used to inform the decision such that the activity no longer has a positive NPV.
<u>SSEH and SSES</u> The CBAs are from 2020/21 and therefore not changed for 2022/23.

Cost benefit analysis additional information Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each activity reported in column C in the Regulatory Year under report.
<u>SSEH and SSES</u> LV Cable Upsizing CBA 2021/22 11kV Cable upsizing CBA 2021/22 Cable losses reductions calculations v4 2020 updates 6.6 to 11kV upgrade CBA 2021/22 33kV Transformer CBA 2021/22 66kV Transformer CBA 2021/22 132kV Transformer CBA 2021/22 Pre-1960 Transformer replacement CBA 2021/22 SSES and SSEH Electricity Theft Calculation 2021/22

E5 – Smart Metering

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.
<u>SSEH and SSES</u> <u>Smart Meter Communication Licensee Costs (pass through)</u> Values submitted relate to actual costs incurred as invoiced by the Data Communications Company (DCC) and costs associated with external audits as defined in the Smart Energy Code. <u>Smart Meter Information Technology Costs (pass through)</u> The values submitted relate to actual expenditure incurred on additional IT assets and services (including hardware and software ongoing costs) which are specifically associated with the systems required to access, store, process and use smart meter derived data.

Actions to deliver benefits Detail what activities have been undertaken in the relevant regulatory year to produce benefits of smart metering where efficient and maximise benefits overall to consumers. At a minimum this should include: • A description of what the expenditure reported under Smart Meter Information Technology Costs is being used to procure and how it expects this to deliver benefits for consumers. • A description of the benefits expected from the non-elective data procured as part of the Smart Meter Communication Licensee Costs. The DNO should set out how it has used this data. • A description of the Elective Communication Services being procured, how it has used these services, and a description of the benefits the DNO expects to achieve.
SSEH and SSES No benefits have been delivered in this regulatory year due to the limited volume of SMETS1 and SMETS2 meters available to us and consequent lack of data available. In addition, the quality of smart meter data has delayed the realisation of benefits but is being addressed by the industry smart meter programme.

Calculation of benefits Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.
N/A

Use of the RIIO-ED1 CBA Tool DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the worksheet in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each activity reported in the Regulatory Year under report which are used to complete the worksheet must be submitted.
N/A

Cost benefit analysis additional information Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.
N/A

E6 – Innovative Solutions

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

General E6 Assumptions for All Technologies – SSEH & SSES

Costs represent the cost of the technology only i.e. it doesn't include associated costs in the CBA such as reinforcement costs. Costs include purchase as well as lease costs.

MVA released represents the MVA released by the technology only i.e. it doesn't include associated MVA released by reinforcement as shown in the CBA.

Estimated gross avoided costs are the gross costs avoided by the technology plus the actual cost of implementing the technology. It doesn't include NPV costs e.g. for ANM.

Pole Pinning:
(First added 2016/17)

This is where poles reaching end of life are pinned to extend their lives.

Cost of replacing one pole: This is taken from the RIIO-ED1 2016-unit cost sheet. The values vary slightly for the north and south networks and so have been separated in the CBA.

PP Tractor/Beaver Cost per month: This is the cost involved in hiring the pole pinning beaver tail machine.

The annual hire cost of the machine has been split up into 12 separate months to come up with a monthly figure.

Pole pinning cost per pole: This is the cost involved for pinning a single pole i.e. labour costs, pole pinning material costs.

# of poles pinned: The number of poles that were pinned in any given month.

Total pole pinning cost: Total costs of pinning poles for any given month. This is also the method investment used in the asset deferment table (see CBA).

Replacement cost avoided: This is the cost that would have been spent had the poles been replaced rather than pinned. This is also the base investment figure that is used in the asset deferment table.

Method NPV: The NPV costs involved in pole pinning based on the assumption that one pole, once pinned, does not need to be replaced for 14 years. This is calculated using the asset deferment benefits table.

NPV Saving: The actual saving of replacing a pole based on a pole's life being extended 14 years before it needs to be replaced. It is the base investment minus the method NPV. All calculations are demonstrated in the CBA

2016/17 Update: Pole pinning has been stopped. However, costs were incurred as it took time to take the machine off hire.

2017/18 Update: Benefits no longer recorded as technology is not in use.

Hybrid Generators – SSES
(First added 2020/21)

This is a temporary mobile generator that is a combination of a diesel generator and a battery storage system (see the "General" section for more details).
Assumptions Aare as follows:

- Diesel consumption is assumed to be 40 litres per 24 hours for a standard 30kVA diesel generator and 86 litres per 24 hours for a hybrid Hygen MX 26kVA generator based on information from our mobile generation teams.
- Hybrid generators consume more diesel per hour than diesel generators as they charge the battery at higher loading levels to optimise efficiency. Over a 24-hour period however the hybrid generators use less diesel than a standard diesel generator (as they are compensated by the battery).
- Fuel savings are calculated based on the loading levels of the hybrid generators
supplied by Victron Energy who provide IT support for the generators.
- The time the hybrid is in "bulk" mode (or charging the battery) is used to calculate fuel consumption at the above rate. This is compared with running a diesel generator for the entire time the hybrid is active, i.e in bulk mode or "inverting" mode (running off the battery).
- Fuel costs have been based on the average cost of red diesel over the year.
- Refuel savings are based on the fuel consumed per month in relation to the fuel tank size, e.g Hygen MX generators have a 100-litre fuel tank – if 158 litres of fuel are consumed in a month this will result in one refuel event. It is assumed that each refuel event costs £180, in time and travel costs. The diesel used and associated with the refuel events is calculated separately.
- Purchase costs are assumed to be the difference in cost between purchasing Hybrid MX 26kVA generators versus 30kVA diesel generators.
- CO2e calculation = Number of litres of fuel (red diesel) used x 2.68787 = kg CO2e emitted. This figure has been taken from DECC carbon conversion factors.
- The difference between the CO2 emitted by a hybrid and a diesel generator is assumed to be the saving.

2021/22 Update

- Data for September, October and November has been averaged based on other months of the Regulatory year because data was missing for these months.

- This is due to data only being retained for 6 months by the hybrid generators, and staff recording benefits annually. Frequency of benefits recording for hybrid generators has now increased to prevent this happening again.

2022/23 Update

- Calculations: Benefits are based on running costs, refuelling costs and cabon emissions of the hybrid generator when compared to those of a diesel generator for the same running time.

- Data for hybrid generation calculations: Average fule consumption ranges between 1.6 and 3.5 litres per hour. For the purpose of the calculations an average of 2.6 litres per hour will be used.
- Data for a comparable size diesel generator is used:
  - Generator size: 30KVA,
  - Fuel usage - 5.4l/h;
  - Fuel tank - 100 litres.
  - Diesel prices updated monthly to reflect current large price fluctuations
- Refueling assumptions:
  - A diesel generator needs to be refueled daily
  - A hybryd generator needs to be refueled once every 3 days, however actual refueling data will be used
  - Refueling costs are a combination of diesel cost, and delivery charges - up to date information will be provided monthly by the diesel generation team

Live Line Tree Harvesting – SSEH
(First added 2016/17)

This is where tree felling occurs by a specialised machine working adjacent to a live line (see the "General" section for more details).
Assumptions are as follows:

- Conventional Harvesting under outage with generation
- CIs & CMLs: Benefit is calculated based on 50% of the unplanned value given this work is carried out during a planned shut down only. As customers must be disconnected from mains supply onto generator supply while carrying out this work, then disconnected from generator supply to go back onto main supply this means CIs are doubled when calculating the cost of CIs.
- Staff costs: These include staff, senior authorised personnel, and standby staff. They are calculated by using estimated daily costs multiplied by the number of days they are required for.
- Generation costs: This includes estimated generator equipment costs based on the assumed outage, the size/type/number of generators and number of days used.
- CI / CML Generator trip costs: The CI / CML costs are calculated assuming there is a 5% chance that the generator will trip for a 4-hour period before power is restored. Staff generator trip costs are incurred as staff are required to attend faulty generators. This is calculated by multiplying £500 (average staff costs to attend and fix faulty generators) by the percentage likelihood that the generator will trip (5%).
- Live Line Harvester Costs: Based on costs incurred by SSEH. The contractor harvester was offhired in 2020/21 due to Covid, so there are reduced costs associated with this versus previous years.
- Potential system security: This includes CIs and CMLs that could occur if a fault developed on a nearby circuit that usually can be back-fed. However, without a live line harvester, the circuit that usually can back-

feed has manual tree cutting taking place and can't be used to supply power. Manual tree felling work must be done during a planned shutdown over several weeks. This puts other customers at risk if a fault develops as supply can't be back-fed. As a result, an additional 5% of CI/CML values is added to take account of this additional risk.
- All calculations are presented in the CBA workings tabs.

2022/23 Update
- Significant increase in recorded benefits for 2022/23 attributed to removal for fuel exemption and requirement to fuel generators with white diesel.
- 2021/22 savings have been updated due to a significant change in diesel prices (as above)
- Both CI and CML values for years 2016-2022 have been recalculate using the Ofgem CI and CML conversion formulas.

Forestry Mulcher – SSEH
(First added 2017/18)

This is a specialised machine that is designed to clear small trees and shrubs underneath OHL (see the "General" section for more details).
Assumptions are as follows:
- Hand felling: Assumptions must be made to calculate how much the forestry mulcher costs vs the traditional hand felling methods:Hand felling labour costs are estimated at an average of £225 per day.
- Hand felling costs also include the hiring of a chipper machine at £250 per week and vehicle hire estimated at £1,171 per month.
- Chainsaw fuel costs are estimated at £15 per day.
- Chipper fuel costs are estimated at £22.80 per day.
- Number of days work estimated by tree cutting manager.
- Forestry mulcher: Labour & vehicle hire costs are the same as hand felling costs.
- Cost of the Mulchers has been incurred via NIA project. 10% of project costs have been included here to reflect costs.
- All costs, above, have been obtained from consulting the tree cutting team manager who has access to costs.

2020/21 Update:
Two new Robocut mulchers were purchased at additional cost which is reflected in the CBA.
- Forestry mulchers are currently not in use due to mechanical issues. This has resulted in fewer benefits being realised this Regulatory year.

2022/23 Update:
- Forestry mulchers stood down from April to October following an incident. Transmission formed dedicated Tree Cutting team. Mulcher benefits recorded November to March associated with Distribution only.

Active Network Management (ANM) – SSEH & SSES
(First added 2015/16)

This is where SSEN deploys flexible solutions to avoid or defer reinforcement to overcome network capacity issues SSEN have multiple ANM schemes with the CBA assumptions detailed below:

Western Isles (WI) ANM – SSEH

- Option Baseline: This is the do-nothing scenario. It is assumed that no investment or network upgrades are considered, meaning new generation cannot connect. As this scenario is unlikely to occur the benefits of ANM have been calculated against Option 2 (Traditional Reinforcement).
- Option 2 (Traditional reinforcement): As we are at the limits of our network's capacity on the island, new generation will require network reinforcement which will have a cost and time impact for the generator. For example, it is assumed a generator requesting a new connection in 2020 would be quoted approximately £20m in 2016. This is because a sub-sea cable reinforcement would be necessary to increase capacity, taking approximately 3 years to complete. In this scenario generators can't operate until 2020, once the subsea cable reinforcement is complete. The £20m reinforcement releases an additional 9MVAof capacity once works have completed (approximately 3 years).
- MWhs of renewable generation have been calculated by using actual generation export values from WI ANM generators & accounts for the fact that this generator was constrained by 0.09% over the one-year period it was operational.
- Option 3 (Install ANM and defer reinforcement): Instead of going ahead with the traditional reinforcement proposed above in Option 2, we have implemented a single generator ANM scheme on the WI. ANM allows us to offer generators requesting a connection to be given a constrained connection instead. ANM has freed up an additional 9MVA of constrained capacity on the WI network without the need for expensive reinforcement. This capacity has already been filled.

2021/22 Update

In previous years narrative, we have noted the savings associated with introducing an ANM scheme for the Western Isles, these savings are recorded as ~£20m - which would have been spent on reinforcement if an ANM solution was not available to SSEH. We are giving further clarification in this year's narrative regarding these savings.
Overall savings would sit at ~£20m, however these savings would be split across connecting customer funded and DUoS customers, at a split of:

- Total Savings = £18.88m (12/13 prices)
- Funded by DUoS (SSEN cost) = £1.34m (12/13 prices)
- Paid by connecting customer = £17.5m (12/13 prices)

Under the E6 tab under the Environment and Innovation pack, we have updated Column M (Costs) and O (Savings) from 'V4 Other Asset Movements' to 'C2 – Connections' and 'CV1 – Primary Reinforcement' respectively. This update reflects costs and savings more accurately.

2022/23 update

In previous submissions SSEH included avoided reinforcement costs associated with the implementation of the ANM scheme on WI. However, this has now been removed. The reason for removal is the driver for the ANM scheme was for a commercial constraint, and savings associated would not apply to SSEH or DUoS customers.

Orkney ANM – SSEH
(First added 2016)

- This has been operational since before the start of RIIO-ED1.
- Running costs have been recorded against each year where they were incurred. Avoided reinforcement occurred pre RIIO-ED1 and so benefits and MVA released have not been counted again here. The main benefit in ED1 is from reduced carbon emissions because of renewable generation being connected via ANM.
- In September 2020 the Orkney ANM scheme was re-opened for new connections. Several applications have been received which could lead to new renewable generation connecting in the future.
- More information can be found here: https://www.ssen.co.uk/our-services/flexible-solutions/flexible-connections/

Isle Of Wight (IoW) (ANM) – SSES
(First added 2015)

- Option Baseline: This is the traditional reinforcement option and assumes a £38m (12/13 prices) reinforcement is triggered in 2018 to allow 100MVA renewable generation to connect from 2022 onwards.
- Option 2 (Install ANM and defer reinforcement): This option installs ANM which allows an increased capacity on the network of 45MVA. It is assumed the £38m (12/13 prices) reinforcement is deferred to 2029 (although this could be longer).
- Only the MVA released by ANM scheme has been included.
- The CBA will be updated each time capacity is filled by generators.
- Estimated Gross Avoided costs: As new generators connect to the IoW ANM scheme the costs of avoided traditional reinforcement are calculated - as more new generators connect, the more of the ANM capacity is taken up and therefore the avoided costs may change (as reinforcement will need to be brought forward)

2021/22 Update

- For the Isle of Wight ANM scheme, we have updated Column M (Costs) and O (Savings) from 'V4 Other Asset Movements' to 'C2 – Connections' and 'CV1 –Primary Reinforcement' respectively.
- If the full reinforcement for the Isle of Wight took place – i.e., ANM was not a feasible option, then the full costs would fall into CV1 – Primary reinforcement and be picked up via our Load Related Expenditure allowance. Figures for gross avoided costs have are £42.64m (2017/18.)

Values in previous submissions was in 2012/13 prices, now updated to 2017/18 prices.

*Alongside the commentary for the Environment and Innovation pack, we have submitted an independent report detailing the savings made (Load reinforcement costs avoided) by the introduction of the ANM on Isle of Wight and the CMZ at Logie Pert.

3rd Party ANM – SSEH
(First added 2016)

In 2020/21 SSEN had three 3rd Party ANM Schemes. This is where generators connect earlier than planned, on a flexible basis, and therefore create carbon benefits by increasing the amount of renewable generation on the network.

- Carbon benefits are calculated by taking total MWhrs of operation over the regulatory year and using the Ofgem conversion methodology within the CBA.
- All three early access ANM schemes were decommissioned between October and November 2020. This is due to the network reinforcements now being complete, so the generators can export fully without the need for ANM.

Constraint Managed Zones – SSEH
(First added 2019/20)

This is where flexible solutions are used to offer security of supply during times of peak demand, planned maintenance or fault conditions (see the "General" section for more details).
Assumptions are as follows:

- CMZ has been used on the Isle of Islay, and in 2020/21 a new scheme on Western Isles was commissioned to support the network following the subsea cable fault between the Isles of Skye and Harris.
- The generation costs of the CMZ schemes are based on the costs agreed in the contracts with the generators.
- It is assumed that had the schemes not been in place, temporary diesel generation would have been required to cover the equivalent generation that was provided by the generators. This is assumed to cost £198 per MWh for temporary diesel generation on Islay and £150 per MWh on Western Isles.
- Diesel generation is cheaper on Western Isles as there is a designated generation site on the island in the form of Battery Point, meaning generation is more efficient.
- Avoided carbon emissions are based on the renewable MWh generated by the CMZ schemes multiplied by the GHG conversion factor in the fixed data tab of the ofgem CBA.

Logie Pert CMZ – SSEH
(First added 2022/23)

This is where flexible solutions are used to offer security of supply during times of peak demand, under network intact conditions. The following assumptioms have been made:

- CMZ has been used at Logie Pert in 2022/23 to reduce the level of generation during a 12 hour low demand period. This has been driven due to the erosion of minimum demand. The hope is to avoid reinforcement as the anticipation is for demand to grow over time.
- The cost of the service is based on the costs agreed within the contracts with the generators.
- The avoided reinforcement is approximately £1.8m (in 2022).
- Carbon emissions are based on the open network carbon reporting methodology. Due to SSEN requesting a generation turn down service the carbon figures are positive (i.e adding carbon).

Alongside the commentary for the Environment and Innovation pack, we have submitted an independent report detailing the savings made (Load reinforcement costs avoided) by the introduction of the ANM on Isle of Wight and the CMZ at Logie Pert.

LV Automation (Bidoyng) – SSES
(First added 2016/17)

This technology is based on a smart fuse auto recloser which can also assist in the location of LV underground cable faults via fault location services (see the "General" section for more details). The assumptions are as follows:

- BD1 calculated data: BD1 faults cause a primary fuse rupture. This is where a fuse ruptures once and the LV Automation unit activates preventing customers from going off-supply. In this situation we get both CI and CML savings as an outage was prevented. It is assumed a 134-minute fault is avoided for each BD1 as this is the average time taken to replace a fuse.
- BD2 calculated data: BD2 faults cause a secondary fuse rupture. This is where a fuse ruptures, is replaced by the unit and then the replacement fuse also ruptures. In this situation customers are off supply so there are only CML savings to be made. As field staff are alerted to the fault by the LV Automation unit, restoration times are generally faster than with a standard fuse rupture. CML savings are therefore calculated by subtracting the time taken to restore the power from the average time taken to replace a fuse (134mins).
- BD3 calculated data: BD3 faults use Kalvatec's location services to identify rogue circuits before the fault has become permanent. In this situation we have CI and CML savings for up to 4 fuse ruptures and CML savings at half cost for one permanent cable fault repair (assumed to be 180 mins).
- # of CIs: This is the total number of customers that could be affected by an LV fault. It is calculated by taking the total number of customers on each feeder and dividing it by 3 to find the average number of customers per phase. As the fault is likely to occur on one of the phases not all customers lose supply. If faults occur on more than one phase these additional affected customers are added to obtain a final figure of

how many customers could have been interrupted. The number of customers is multiplied by £12.5485 for 2020/21 (exact value depends on the year) to obtain a customer interruption figure.

- # of CMLs: This is the duration of time that customers that have been interrupted as calculated by BD1, BD2 and BD3 methodology.
- BD3 calculated data: BD3 CIs and CMLs occur where a fault has been located using Kelvatec's "go locate" location services.
- It is assumed that rogue circuits (circuits prone to faulting), where LV Automation equipment is located, will have an average of 4 fuse ruptures on them before the fault is located and fixed. If a cable problem is located before a circuit faults and causes a fuse operation, then the maximum number of CIs and CMLs are saved i.e. CI / CML multiplied by 4 (the average number of times the fuse would have ruptured because of the fault). The more fuse ruptures that occur, the less CI / CML savings occur. Once 4 fuse operations have occurred no more CI / CML savings can be gained (as it is assumed 4 is the number of times a fuse will rupture before the fault is fixed).
- On top of this there is a CML saving associated with fixing the fault identified with Kalvatec's location services before it becomes permanent. As the fault has been located before customers go off supply, a preventative repair can be planned. This planned outage is assumed to be at half the CML cost of an unplanned outage (but will occur the same number of CIs). Calculation details below:
    - 0 fuse operations =Number of CIs and CMLs multiplied by 4
    - 1 fuse operation = Number of CIs and CMLs multiplied by 3
    - 2 fuse operations = Number of CIs and CMLs multiplied by 2
    - 3 fuse operations = Number of CIs and CMLs multiplied by 1
    - 4 or more fuse operations = Number of CIs and CMLs multiplied by 0
    - Fault repair = Number of CIs multiplied by 1, number of CMLs divided by two CMLs (fuse operation): It is assumed that one fuse rupture will cause an outage of 134 mins.

  This has been reviewed for 2020/21 and is based on average fuse restoration times for LV faults.
- CIs (fuse operation): It is assumed that one fuse rupture will cause an interruption for all customers on that circuit.
- CMLs (fault repair): It is assumed that a transient fault located will result in a repair. This will cause an outage of 180 mins which is based on the average fault restoration time for 2020/21 for permanent cable faults.
- CIs (fault repair): It is assumed that each fault located and repaired will cause an interruption for all customers on that circuit.
- Additional costs: These include PSI costs, backfeed costs, operations costs and excavation costs as explained below:
- PSI costs: These are planned supply interruption costs. It is estimated that an average cost of £995.96 will be incurred as a result of planned interruptions being necessary due to specific faults on specific circuits. This is an average figure taken from the LV Automation business case, which takes into account average PSI costs.

- Backfeed costs: These are average costs incurred as a result of backfeeding being necessary. It is estimated that an average cost of £1991.93 will be incurred if backfeeding is required. This figure has been derived from the LV Automation business case, which takes into account average costs of backfeeding. Backfeeding savings only occur on BD3 faults i.e. faults that are transient in nature and are cleared by the automatic replacement of fuses due to the technology. This is because it prevents the need for backfeeding being necessary.
- Operations costs: This is the cost of labour required to change a fuse. As stated above there are on average 4 fuse ruptures before a fault on a rogue circuit is located and fixed. Identifying fault locations using Kalvatec's location services will avoid these fuse ruptures. We assume a 2 hour saving for each fuse rupture avoided at a cost of £32.20 per hour, based on average staff costs
- Excavation costs: LV Automation creates an average estimated saving of £1250, per fault, in terms of reduced excavation costs. This figure comes from the TOUCAN NIA project. This is because it can pinpoint underground faults more effectively, reducing the need for multiple excavations
- BD1 Duplicate Removal: On occasion a fault can trigger both BD3 and BD1 operations. When this happens CI and CML savings will be recorded for both BD1 and BD3. These duplicate savings are deducted to prevent double counting.
- Total costs: This is a summation of all costs stated above, removing the double counting.
- Total contracts spend: This is the amount of money spent on the LV Automation contract specifically for fault location and fuse replacement services (refer to workings template tab in CBA).
- Total incentive spends: This is the total amount of money that Kelvatec, the LV Automation contractors, are awarded on top of the normal contract due to accurately locating faults.
- Total LV Automation spend is the addition of these two spends.

2022/23 Update

- BD1 calculated data: It is assumed a 159-minute fault is avoided for each BD1 as this is the average time taken to replace a fuse.
- BD2 calculated data: CML savings are therefore calculated by subtracting the time taken to restore the power from the average time taken to replace a fuse (159mins).
- BD3 calculated data: CMLs (fuse operation): It is assumed that one fuse rupture will cause an outage of 159 mins.

Thermal Cameras – SSES
(First added 2018/19)

Thermal cameras are used to assist in LV underground cable fault location where they reduce CMLs and occasionally CIs if defects are located prior to a fault occurring (see the "General" section for more details).
Assumptions are as follows:

- CML savings are calculated depending on the type of circuit the fault occurs on.
- Rogue circuit: Where 5 or more faults have previously occurred. It is assumed this type of circuit will fault at least 4 more times prior to becoming a permanent fault i.e., replacing fuses no longer restores supply.
- A multiplier of 4 is used when calculating faults located and repaired on these types of circuits.
- Faults located and repaired are assumed to save 90 mins, based on NIA: TOUCAN field trial experiments.
- Non-Rogue circuit: No multiplier occurs to the 90 min CML saving.
- CI savings occur if a defect is discovered before a fault becomes permanent. Savings are based on the number of customers on the circuit multiplied by the CI fine e.g., £12.5485 for 2020/21 (varies each year).
- Excavation savings are estimated at £1250 per excavation avoided (max 1 per fault attended). These figures have been calculated by our automation team

2022/23 Update

This technology has now reached its lifespan and new models may be considered for use in the future as part of the Low Voltage Underground Technologies Methodology introduced in 2021.

Low Voltage Underground Fault Location Technologies – SSES (First added 2021/22)

LV underground cable faults cost over £12.4m in Customer Minutes Lost (CML) across SEPD in 2019/20. This equates to over 77.3% of SEPD's total LV CML costs. This outturn is consistent with the two preceding years.

SSEN has been investigating new tools and methodologies that better detect and locate LV underground cable faults and improve restoration times, decrease CMLs and reduce associated excavation and operational costs.

The Network Innovation Allowance (NIA) funded projects LV Underground Fault Location Technologies (LV UFLT) and Phase Identification Unit to Assist in Underground Fault Location (PIU) which demonstrated that:

- The additional fault-finding equipment trialled in the NIA projects is more effective in pinpointing the locations of underground faults compared with the current approach.

- Performance can be further improved by adopting a more structured fault-finding process with supporting methodologies to ensure the most appropriate fault-finding tools are consistently utilised.

These additional technologies complement the current LV Fault Location toolbox of Thermal Imaging Cameras and Cable Sniffers. Expanding the toolbox to include the LV UFLT acoustic equipment, PIUs and associated fault-finding methodologies will reduce CML and excavation costs whilst providing a consistent work method and fault-finding standard for Rapid Response Operatives (RRO).

The LVUFLT methodology equips and trains RROs in optimal LV underground fault-finding techniques. As RROs are the first person on site, this method increases the probability of faults being located accurately and efficiently, improving CML performance, reducing the requirement for additional personnel on site and potentially avoiding unnecessary excavations subsequently increasing the overall experience for customers.
The trials undertaken in the NIA project demonstrated that over 80% of faults were located by RROs using the full suite of LVUFLT techniques, compared with 26% of faults located by RROs in the baseline. This resulted in an average of 55.6 minutes saving per fault using the LVUFLT process. This saving was achieved as the RROs were able to progress the fault location without having to wait for support from either jointer or team managers.

PIU NIA project trialled the use of PIUs in isolation. The PIU can identify a premises supply without the need to gain entry. This information can be used to quickly identify which customers are off supply in the event of an outage, as well as confirming supplies have been restored when repairs are complete. The PIU was particularly beneficial in instances where it was not possible to gain entry during fault location – "No Access Jobs".

Additionally, the PIU can support the user when identifying the fault zone of an LV Underground Fault, through the identification of "who's on and who's off". Operatives, without a PIU, can do this currently but when a property, or properties, with "No Access" arise the opportunity is less accurate. In this instance a PIU's support is unique – A property's supply can be identified without having to access a Customer's Property. In this scenario the PIU can aid the reduction of excavation costs and the reduction of time to restore when locating and LV Underground Fault. The cost of each additional excavation, on a LV Underground fault, is currently estimated at £1250. By avoiding the need to "dig a second hole", to confirm the fault location, the NIA Project also identified a time saving of approximately 2 hours.

General
For each of the solutions please explain:

- In detail what the solution is, linking to external documents where necessary.
- How this is being used, and how it is delivering benefits.
- What the volume unit is and what you have counted as a single unit.
- How each of the impacts have been calculated, including what assumptions have been relied upon.

Pole Pinning
****This technology is no longer in use and so benefits are no longer recorded****

- Poles reaching their end of life or those that are significantly deteriorating to the point where they need to be replaced, can instead be pinned. Pole pinning involves using a specialised pole pinning machine that drives a pin through the base of a deteriorating pole. The pin provides the pole with additional strength. It is estimated that pinned poles will have their lifetime extended by 14 years, providing significant financial benefits.

- Unfortunately pole pinning failed to deliver positive financial benefits and the technology has been stopped by SSEPD. This is because not enough poles were being pinned to cover the cost of the equipment hire. Field staff reported problems such as poles being too rotten to pin. It has also been discovered that pole pinning has a negative effect on asset health indices, so it was decided to stop pursuing use of this technology.

- The volume unit is the number of poles pinning machines owned by SSEN.

- Assumptions and how they have been calculated are mentioned in the first box.

Hybrid Generators – SSES

- The Hybrid Generator (HG) technology is offered as a solution for off-grid power supply requirements in remote locations and can be used to provide power for residential, construction, telecom towers and disaster relief applications. It is a temporary mobile generator and not utilised full time. The HG is a combination of a diesel generator (DG) and a power-electronic converter with integrated battery storage. Hybrid generators use diesel to charge a battery which is then used to cover an outage. This is efficient as the battery can be charged at optimal loading levels and then the diesel generator can be switched off, meaning less diesel is consumed overall than with a standard diesel generator. In conventional DG applications, generators provide electricity to meet customer demand. As this demand is often at lower loading than the generator is spec for, the DG is constantly running, but operating at off-optimal conditions for most of the time. The battery system of the Hybrid Generator alleviates this requirement, as the HG can use the battery to meet low load customer demand. Other benefits include low/no noise through noise insulation and operation in battery-only mode, less carbon emissions through operation of the DG under optimal conditions and use of battery, generally more efficient operation than that of the DG and reduced cost of ownership since the engine has to run less often. In 2020/21 SSES procured an additional 5 new model "Hygen MX" hybrid generators to compliment the 5 purchased in 2019/20. The closedown report is located here: ED_SSE - RRP - 2016-16 RRP\2011_14 Hybrid Generator LTI Close down report

- Hybrid Generators have been in use since June 2019 and are delivering benefits in fuel savings, refuel savings and reduced carbon emissions compared to traditional mobile diesel generators as detailed in the "Allocation and estimation methodologies" section.

- The volume is based on one generator equalling one unit.

- The assumptions and calculations are described in the "Allocation and estimation methodologies" section of this report.

Live Line Tree Harvester - SSEH

- Tree harvesting adjacent to our overhead network presents increasing challenges to SSEN particularly in SSEH. Volumes of timber available to be harvested by third parties will continue to rise over the next 20 years and we have increased ESQCR obligations to gain enhanced (falling distance) clearances over the next 25 years.Current guidance and practice on tree felling within falling distance of the network is to either provide an outage, or to fell and dismantle the trees using manual techniques.

- Providing an outage has obvious disadvantages:
- significant CI/CML consequences
- hazards associated with switching and provision of generation
- reduction in network security
- time constraints on shutdowns could result in failure to complete works
- machinery breakdown might result in further outages being required

- The use of manual methods adjacent to a live line for large numbers of trees also has significant drawbacks:

- unacceptable exposure to hazard to operatives over long periods from working at height, chainsaws, falling trees and electricity
- drain on highly trained resources needed to carry out programmed maintenance work
- The objective of the project was to fully investigate the scope of the issue, evaluate potential methods and machinery that could be employed and to develop safe systems of work to carry out mechanised harvesting adjacent to a live network.

- The close down report is located here: ED_SSE - RRP - 2016-16 RRP Returns\Live Line Harvesting Closedown Report

- The harvester works by felling trees adjacent to live lines. It produces benefits as it is a far less costly method of harvesting vs conventional hand felling methods. It is also far more efficient. Benefits come from reduced CIs / CML, improved security of supply (also CI CML benefits) and lower generation costs. Unquantifiable safety benefits also exist, as hand felling of trees for long

- periods of time carries risks.

- The volume of units is the number of live line harvesters owned by SSEN. SSEN have historically used two harvesters in SSEH, one purchased and one contractor unit. In 2020/21 this was reduced to one unit as the contractor machine was offhired due to the Covid-19 pandemic. This has not been counted as a disposal however as SSEN did not own the machine.

- Assumptions and how they have been calculated are mentioned in the "Allocation and estimation methodologies" section of this report

Forestry Mulcher - SSEH

- The forestry mulcher is a machine designed to remove small shrubs and woody species underneath OHL. More details can be found in the close down report: https://www.smarternetworks.org/project/nia_ssepd_0018/

- The mulcher is currently being used in SSEH where there is a higher proportion of vegetation. The mulcher can't cut vegetation too large or mature and so its prime purpose is for controlling new growth. It is estimated to be 3.8 to 3.4 times more productive than hand felling based on time savings experienced during the NIA trial. This means more spans can be cut per £ spent, improving unit costs.

- Units are the number of machines that are in use. In 2020/21 SSEH procured two new Robocut mulchers to replace the old Bushfighter models, thus there is an addition and disposal of 2.

- Assumptions have been detailed in the "Allocation and estimation methodologies" section of this report.

ANM – SSEH & SSES

- The ANM solution is deployed where renewable generators may otherwise have been unable to connect to the distribution network due to network capacity issues resulting in excessive reinforcement costs or timescales. It allows a greater number of generators to connect on a flexible basis and allows export up to a certain limit before generators are constrained in merit order. The system uses Information Communication Technology (ICT) architecture that monitors, in real time, the pre-identified network constraint points and ensures that no generators connected through it can breach the network's operational limits. If those limits are threatened then the system sends control signals to the generator to reduce their export until the network limits are no longer threatened, then the generators are released back to a safe operating state. The key governing principles are described in the ENA produced ANM Good Practice Guide, which can be found at the following link: http://www.energynetworks.org/assets/files/news/publications/1500205_ENA_ANM_report_AW_online.pdf The report was created by the ENA ANM Working Group where the relevant subject matter experts meet to share learning and to tackle industry wide issues affecting the wider roll out of ANM.

- The volume unit on this is 1 ANM scheme.

- Reinforcement costs for each ANM scheme have been calculated by system planners based on the reinforcement required to ensure additional capacity is available for new connections.

- The assumptions for each scheme have been detailed in the "Allocation and Estimation Methodologies" section

3rd Party ANM - SSEH

- There are two types of 3rd party ANM connections for the customer to consider - shared capacity and demand management. Both of which are installed and managed by the customer. Shared capacity example: An existing generator may have a contracted capacity of 10MW but only have 6MW of connected generation. Therefore, there is the potential for a customer to approach this generator and make use of the spare capacity. The customers will install a system that will ensure the combined export of both generators does not exceed the contracted capacity. Demand Management example: A new 250kW generator wishes to connect to the distribution network. However due to transmission constraint upstream the generator has a limited export of 50kW. The generator develops a proposal to manage their export to ensure they do not breach the capacity of the network until reinforcements are made. This means they can connect early and export whilst reinforcements are made.

- 3rd Party ANM allows renewables to connect more cheaply and faster. It also allows generators to benefit from government subsidies that are time bound.
- 1 ANM generator counts as 1 scheme. In 2020/21 three 3rd party ANM schemes were decommissioned due to network reinforcements being completed and the generators now being able to freely export without the ANM scheme needing to manage constraints. Thus, there are 3 disposals in 2020/21.
- Calculations are explained in the "Allocation and Estimation Methodologies" section of this report

Constraint Managed Zones – SSEH

- Constraint Managed Zones (CMZ) offer flexible connections on either a temporary or longer-term basis to provide support to the distribution network. SSEN offer four types of CMZ:
- CMZ Sustain – a pre-agreed change in input or output over a defined time to prevent a network going beyond its firm capacity.
- CMZ Secure - the ability to access a pre-agreed change in input or output from a provider based on network conditions close to real-time.
- CMZ Dynamic – the ability of a provider to deliver an agreed change in output following a network abnormality.
- CMA Restore - Following a loss of supply, the Network Operator instructs a provider to either remain off supply, or to reconnect with lower demand, or to reconnect and supply generation to support increased and faster load restoration under depleted network conditions.
- SSEN's second CMZ contract has been operational since October 2020 utilising Restore services in the Western Isles to respond to a subsea cable fault. The contract provides renewable generation from hydroplants on the island in place of diesel generation.

- The main benefit is associated with the CMZ contract providing a more costeffective option for supporting the network outage than traditional temporary generation services. As traditional generation would be diesel based, there are also reduced carbon emissions associated with the CMZ contracts.

- The volume relates to the number of CMZ schemes utilised. As of 2020/21 this are two schemes - Islay CMZ and Western Isles CMZ.

- MWhs of flexibility provided has been given by the generators. This is multiplied by the contract rate to determine the cost of flexibility services provided. Diesel generation is assumed to cost £189 per MWh on Islay and £150 per MWh on Western Isles based on information from our flexible connections team. Carbon savings are based on the Ofgem conversion rate per MWh generated in the fixed data tab of the CBA (currently 0.430 tonnes per MWh).

LV Automation - SSES

- LV Automation uses smart fuses that provides remote fault reclosing, accurate demand data, pre-fault detection and location, post fault location and cable condition assessment. Kelvatek are the vendor who supplies the LV Automation fault detection and automatic re-close equipment. They also provide a fault analysis service which rapidly interprets data from the devices and sends details of fault location to the SSES Supply Restoration Teams.

- LV Automation fault detection equipment is designed to be mobile. It is placed on rogue circuits (i.e. circuits with high numbers of faults) to maintain security of supply through the fuse auto-reclose feature, whilst whilst working to pinpoint the location of the fault. Once a fault is identified and resolved, the equipment is moved to the next location in order to detect and prevent as many faults as possible.

- When the SSES LV Automation team are notified of fault by Kelvatek, a team of field staff are sent out to locate the fault using initial location data provided by Kelvatec. In order to establish a detailed location based on the information from Kelvatek a device from EATL called a 'Sniffer' is used.

- Sniffers are able to detect underground faults by identifying gases that are emitted from arcing and heated cables. Once a fault is located the area must be excavated in order to fix the fault. If the fault is not located the devices continue to gather intelligence gradually building up a more accurate indication of the location of the fault.

- Before LV Automation technology was available, finding faults in the underground network was difficult. This often resulted in multiple excavation attempts in order to identify the fault location. In addition, the length of time taken to locate and repair the fault had a customer impact and resulted in CML penalties.

- The main purpose of the LV Automation project is to locate faults before they cause a customer interruption along with associated customer minutes lost. It does this by identifying pre fault signals, once enough signals have been recorded and analysed it is possible to identify potential fault locations with an associated level of confidence. A team is dispatched to the pre-fault location when the analysis predicts a fault location with an estimated accuracy of +/-10 metres. The team can then locate and repair the faulty cable before it becomes a network fault, in most cases avoiding any unplanned interruptions to customers.

- Uniquely, the equipment also gives the DNO the ability to reclose the circuit remotely in the case of an intermittent fault, avoiding CIs and CMLs associated with traditional fuse rupture and replacement.

- The volume unit is the number of LV Automation contracts, which is one.

- Assumptions and how they have been calculated are mentioned in the "Allocation and Estimation Methodologies" section of this report.

Thermal Cameras – SSES

- Thermal cameras, trialled as part of the TOUCAN NIA project, are used for assisting in the location of LV underground faults. They locate thermal hot spots caused by cables that have faulted or from cables that are likely to fault, as they leave a heat residue behind that the thermal camera is able to locate. This allows SSEN field staff to locate and repair faults quicker, thereby restoring power quicker to customers or even preventing faults from occurring in some cases. The TOUCAN NIA close down report details the technology in more detail: https://www.smarternetworks.org/project/nia_ssepd_0021/documents

- Thermal cameras have been rolled out across our southern network and are currently assisting with LV cable fault location, enabling field engineers to restore power quicker to customers, thereby reducing CMLs.

- The volume of units is expressed as the number of thermal imaging cameras that have been purchased.

- CI and CML saving calculations are described in the "Allocation and Estimation Methodologies" section of this report.

Use of the RIIO-ED1 CBA Tool DNOs should use the latest version of the RIIO-ED1 CBA Tool for each solution reported in the Regulatory Year under report. Where the RIIO-ED1 CBA Tool cannot be used to justify a solution, DNOs should explain why and provide evidence for how they have derived the equivalent figures for the worksheet. The most up-to-date CBA for each solution reported in the Regulatory Year under report which are used to complete the worksheet must be submitted.
RIIO-ED1 CBA tool has been used for all technologies.

Changes to CBAs
If, following an update to the CBA used to originally justify the activity in column C, the updated CBA shows a negative net benefit for an activity, but the DNO decides it is in the best interests of consumers to continue the activity, the DNO should include an explanation of what has changed and why the DNO is continuing the activity.

SSEH

No changes have been made to CBAs that were updated in 2021/22.

SSES

No changes have been made to the existing CBAs.

The hybrid generators are currently showing negative benefits due to the benefits realised not yet covering the purchase price of the units.

There have been changes to the way we calculate benefits of thermal cameras. These have been estimated based on past performance i.e. benefits are an average of the benefits achieved over the years the cameras have been used. This is because the business is going through a change in reporting tools and did not properly record the benefits during this intervening period. Estimated benefits are on the conservative side.

Calculation of benefits
Explain how the benefits have been calculated, including all assumptions used and details of the counterfactual scenario against which the benefits are calculated.

Refer to the "Allocation and estimation methodologies" section for a detailed breakdown on the benefits calculation for each innovation

Cost benefit analysis additional information
Please include a reference to the file name and location of any additional relevant evidence submitted to support the costs and benefits inputted into this worksheet. This should include the most recent CBA for each solution reported in the Regulatory Year under report.

Pole Pinning
CBA Location:
SSEH – Live Line Tree Cutting CBA 2017/18

Live Line Tree Cutter
CBA Location:
SSEH – Live Line Tree Cutting CBA 2021/22

Forestry Mulcher
CBA Location:
SSEH Forestry Mulcher CBA 2021/22

Western Isles ANM
CBA Location:

SSEH Western Isles ANM Benefits 2021/22

Orkney ANM
CBA Location:
SSEH Orkney ANM Benefits 2021/22

Isle of Wight ANM
CBA Location:
SSES Isle of Wight ANM Benefits 2021/22

3rd Party ANM
CBA Location:
SSEH 3rd Party and Early Access ANM Benefits 2021/22

CMZ
CBA Location:
SSEH Islay CMZ CBA 2021/22
SSEH Western Isles CMZ CBA 2021/22
SSEH Lite CMZ CBA 2021/22

LV Automation
CBA Location:
SSES CBA Bidoyng 2021/22

Thermal Cameras
CBA Location:
SSES CBA Thermal Cameras 2021/22

Hybrid Generators
CBA Location:
SSES CBA Hybrid Generator 2021/22

E7 – LCTs

Allocation and estimation methodologies: detail any estimations, allocations or apportionments to calculate the numbers submitted.

Where we are notified that a connection has been made under 'connect and notify' and the installer has not provided all of the information, then we determine the kilowatts based on other details provided.

We have used CC4 of the Connections Pack to calculate the volume of DG connections that are not G83, consistent with previous years. This reports projects which have been financially closed in the Regulatory year. Other projects, that may have been connected in the year but have not been financially closed, will be reported in future years.

LCT – Processes used to report data
(i) Please explain processes used to calculate or estimate the number and size of each type of LCT.
(ii) If any assumptions have been made in calculating or estimating either of these values, these must be noted and explained.

The Electric Vehicle (EV) figures are based on the submissions that we received from the installers of EV. The assumptions are that anything reported as 100A or less is assumed to be single phase and anything >100A is assumed to be three phase. For the EV data we have provided the EVCP draw of each connection.

LCT - Uptake Please explain how the level of LCT uptake experienced compares to the forecast in your RIIO-ED1 Business Plan and the DECC low carbon scenarios. This must also include any expectation of changes in the trajectory for each LCT over the next Regulatory Year in comparison to actuals to date.
In 2022/23 we are continuing to see an increase in EV fast chargers being installed with 274% increase in our SSEH network and 219% increase in our SSES network in comparison to 2021/22.