



SSEN Distribution Response to ED2 Draft Determination - Annex 10: North of Scotland



Scottish & Southern
Electricity Networks

Powering our
community

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Executive summary

Covering the Highlands and Islands, our North of Scotland region, which accounts for 25% of the UK, spread out across multiple islands, and 2% of its population, is the most sparsely populated network in the UK. With an average network density of 14 customers per km² (compared to a national average of 133 per km²), it serves 780,000 customers, a quarter of whom are in fuel poverty and face increasing challenges on the cost of living.

The region is critical for meeting the UK (2050) and Scottish (2045) governments' legally binding net zero ambitions. The remote island communities can act as green energy hubs, accelerating the transition to low carbon technologies.

However, compared to other regions, the North of Scotland has several unique factors that impact on the cost and complexity of day-to-day operations and transformation programmes.

Our RIIO-ED2 Business Plan¹ recognises this and signalled a clear shift towards managing the fleet of subsea cables and back-up generation, using a mix of proactive and responsive replacements to underpin reliability for both increasing demand and generation needs.

Our plan directly responds to stakeholder needs, draws on improved asset data to inform our investment programme, and has taken on board Ofgem's feedback that a more strategic approach was required compared to RIIO-ED1.

Our plan investments are credible and enable transition from RIIO-ED1 to RIIO-ED2. It optimises the benefits of investment, balanced risks and rewards, and allows us to meet legally binding net zero targets.

We believe Ofgem's RIIO-ED2 Draft Determination (DD) is deeply flawed and would result in insufficient allowances. In turn, this would lead to suboptimal outcomes for both current and future consumers in the shape of delays to decarbonisation, a lack of improvements to network resilience, and a widening the infrastructure gap that cannot keep pace with demand.

If enacted in its current form, we believe the DD would have a significant and detrimental impact on both the economy and quality of life in the region, and not allow the region's abundantly available resources be used to support net zero targets.

For example, Ofgem's benchmarking process and DD have only allowed for 5.6km of LV cable for the duration of the price control compared to the requested 164km – this is clearly insufficient to meet our customers' needs.

While we welcome parts of the DD package, such as the Hebrides and Orkney re-opener, the overall DD fails to fully recognise the challenges associated with operating across the region's unique geography and ignores evidence on issues SSEN, our stakeholders and our customers face in the North of Scotland.

Instead of the £212.5m requested in baseline funding for the North of Scotland, we have been provisionally allocated £164.2m. Further, Ofgem has rejected the need for volume-drivers to manage uncertainty and has not excluded from its benchmarking certain specific and unavoidable costs that are unique to this region.

Ofgem's DD would condemn the North of Scotland to an unreliable and insufficient power network.

¹ Throughout this document, we refer to our resubmitted April 2022 Business Plan

Ofgem's approach is irrational in several respects. For example, by not recognising the impact of population sparsity in the North of Scotland, the costs that we must unavoidably incur are treated as "inefficiencies" compared to other networks that have no equivalent costs.

Also, Ofgem has denied us funding for targeted, data-driven, proactive replacement of subsea cables, while also rejecting our "Fix on Fail" volume driver, because we are expected to "... *manage risk relating to their subsea cable portfolio on a proactive basis, underpinned by a robust understanding of the health of these assets*".

These material errors and inconsistencies must be addressed so that the Final Determination (FD) is founded on robust analysis and evidence, to enable us to efficiently deliver the resilient network and outputs that all stakeholders and customers, both current and future, expect and deserve, and the transition to net zero.

The unique characteristics and requirements of the North of Scotland require acknowledgement and incorporation of these specific factors and the interdependency between elements of our plan.

This document seeks to aid Ofgem's understanding of our Business Plan through:

- highlighting the evidence as to why the North of Scotland should be treated differently to other regions
- setting out the correct assessment of our efficiency
- providing confidence that our requested baseline is necessary, value for money, and deliverable
- demonstrating why the risks and challenges we face in the North of Scotland are greater in RIIO-ED2 compared to earlier price controls, and
- setting out the consequences for our customers and communities.

Further details are provided in our response to the DD consultation questions and supplementary information for our Engineering Justification Papers (EJPs).

Supplementary information

We disagree with Ofgem's draft determination on several strategically important North of Scotland topics.

To support Ofgem's decision to further re-assess for Final Determinations, SSEN has generated this annex, plus supporting appendices of information, to provide the justification to address Ofgem's feedback to date. We also reference a number of additional Annexes to be read in conjunction with this Annex 10, prior to Final Determinations for North of Scotland.

<i>Draft Determination response documents (August 2022)</i>	
Annex 10	North of Scotland (NoS) company-specific factors
Appendix A	Subsea cable supplementary information (EJPs)
Appendix B	Remote generation supplementary information (EJP)
Appendix C	Shetland supplementary information (EJP)
Appendix D	NoS consultation questions
Appendix E	NoS SSEN reverse supplementary questions
Appendix F	NoS Business Plan data tables
Appendix G	NoS cost-modelling summary
Annex 1	Advocacy
Annex 5	Material DD issues and impacts on SSEN
Cost Assessment Annex E	Review of the cost assessment in Ofgem's RIIO-ED2 Draft Determinations
Cost Assessment Annex F	Regional wages – An expert submission for SSEN by Professor Ken Mayhew
<i>Previously Submitted SHEPD RIIO-ED2 Business Plan Re-Submission</i>	
Scottish Islands	SHEPD letter to Steve McMahon dated 29 April 2022
<i>Previously Submitted Final Business Plan (December '21)</i>	
Annex 3.2	Future Stakeholder Engagement strategy
Annex 8.1	Scottish islands
Annex 15.1	Cost efficiency
Annex 15.3	Cost-confidence assessment
Annex 15.4	Establishing an appropriate efficiency challenge
Annex 15.7	Company-specific and regional factors for RIIO-ED2
Annex 17.1	Uncertainty Mechanisms

<i>Previously submitted SHEPD document (December 2020)</i>	
23 December 2020	SHEPD Shetland Enduring Solution – DSO recommendation on standby arrangements

SSEN's network in the North of Scotland

Our network in the North of Scotland is unique. It faces different, and often greater, challenges compared to other networks which manifest themselves through higher costs and, in some cases, longer lead-in times. This is due to the region's geography, the nature of the network and the challenges it imposes. Our customer profile is also very distinctive compared to other networks, with very different stakeholder needs compared to other DNOs.

Customers and geography

Our network in the North of Scotland covers 25% of the UK but serves only c.780,000 customers, or 2% of the UK population. Over a quarter of our customers are in fuel poverty and we expect this figure to grow given current cost of living pressures.

Our customers are spread across the Highlands and Islands, with a much lower density than other networks - 14 customers per km² compared to a national average of 133 per km².

Many of these islands are no larger than 5km² which means it is not economic to have full-time staff on them (we do have a small number of event-retained and part-time staff on call-off contracts based on some of the smaller islands).

The difference between our network (SHEPD) and other DNOs is summarised below.

Table 1: comparison of networks (2020)

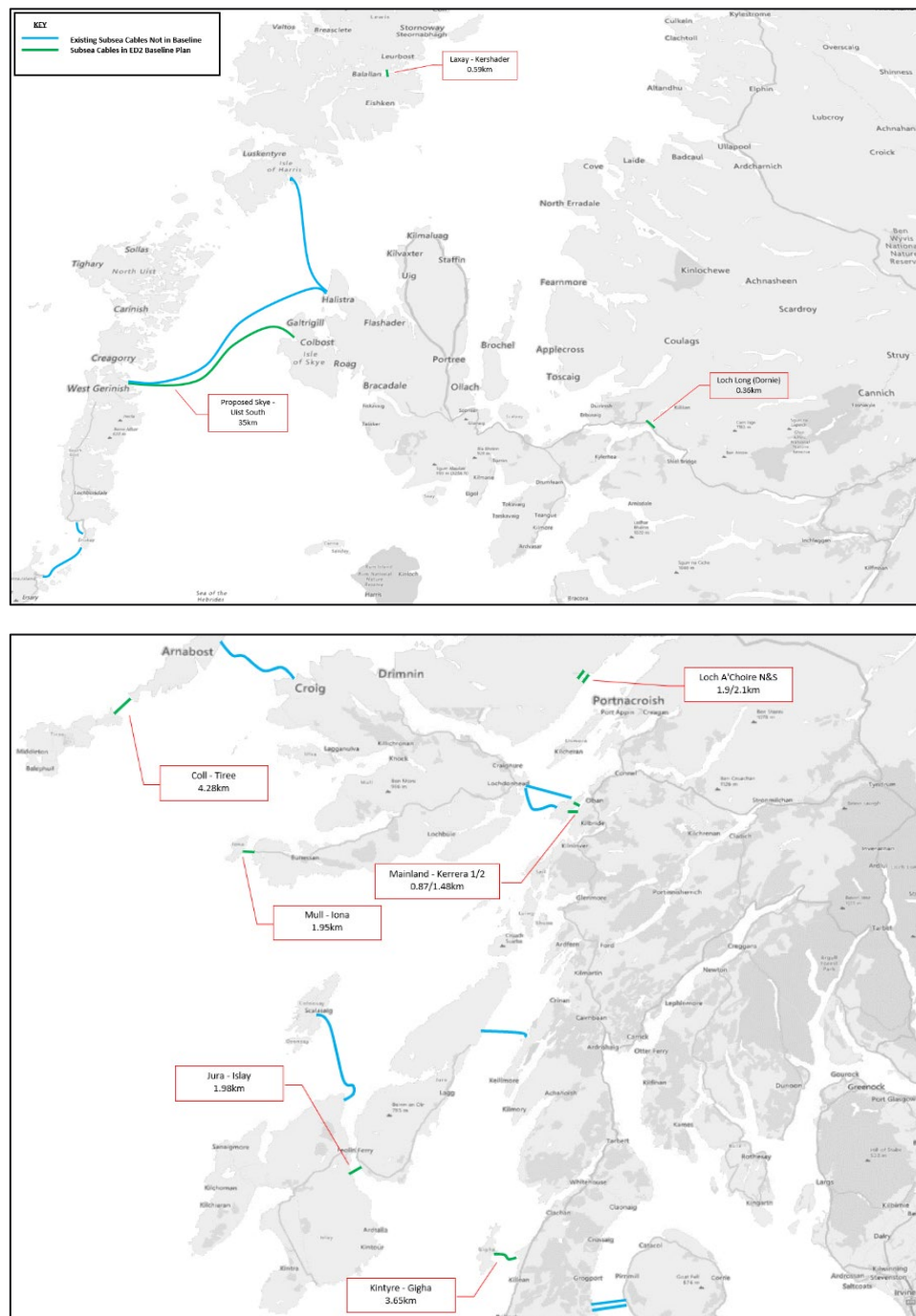
Licence	Area (km ²)	Customers	Network length (km)	Population density (Customers km ²)	Customers per km of network
ENW	12,500	2,399,715	57,432	192.0	41.8
NPgN	25,000	1,610,820	41,923	156.9	38.4
NPgY		2,312,147	54,891		42.1
EPN	21,050	3,653,242	98,379	173.6	37.1
LPN	650	2,369,157	37,423	3644.9	63.3
SPN	8,300	2,311,511	53,256	278.5	43.4
EMID	16,000	2,665,558	74,400	166.6	35.8
WMID	13,300	2,498,337	65,364	187.8	38.2
SWALES	11,800	1,142,731	35,832	96.8	31.9
SWEST	14,400	1,628,987	50,936	113.1	32.0
SPD	21,905	2,008,433	58,697	91.7	34.2
SPMW		1,519,557	47,253		32.2
SHEPD	55,895	782,536	49,414	14.0	15.8
SEPD	19,105	3,092,275	77,943	161.9	39.7

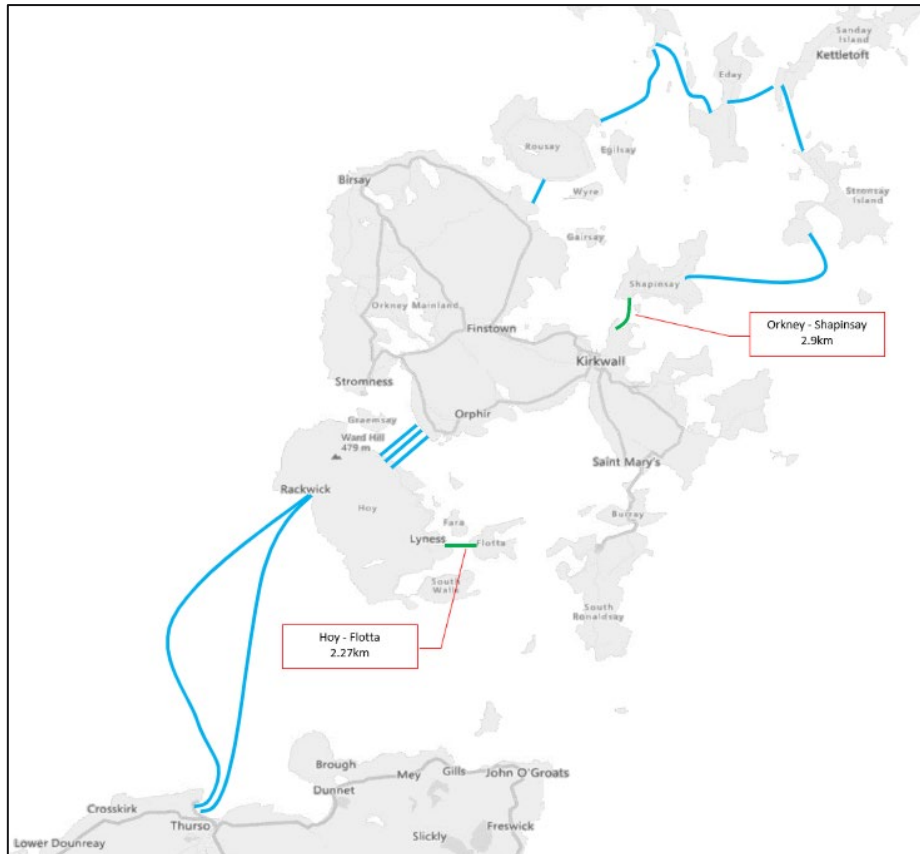
Source: EnergyBrokers, ENW, NPg, SPD, SSEN

The geographic complexity of specific areas of our region is mapped below. The maps show a mix of subsea cables in the baseline for RIIO-ED2 and select existing cables. The regions covered from left

to right are Western Isles, Inner Hebrides and Orkney. Shetland is also included within our region but not shown on the maps below.

Figure 1: North of Scotland region





Source: SSEN

The region is exposed to Atlantic storms, and it is not unusual for winter storms to reach hurricane force. The islands are also subject to higher corrosion rates driven by salt and the extreme climate. Overhead lines are particularly vulnerable to corrosion, increasing the chances of conductor and component failure.

The profile of our customers and the area they live in means we must constantly explore new ways of supporting those who need it the most, investing innovatively and efficiently for current and future customers. Regular stakeholder, consumer and customer engagement is vital.

Network complexity and engineering challenges

While the geography of the region creates several opportunities to maximise the potential of renewables and accelerate the transition to net zero, compared to other DNOs, it also imposes operational challenges for us related to increased complexity and higher costs.

The geography of the region dictates that electricity is supplied via nearly 50,000km of overhead lines and a current network of 110 submarine cables rising to 445km in 2022/23 (with the installation of two further cables) covering 108 separate circuits on 60 islands. The low density of our customers in the Highlands and Islands means the average length of our network per customer is five times the GB average (see table). The differences between our network and other DNOs is summarised below.

Table 2: Comparison of North of Scotland network (SHEPD) with average DNO

DNO	Overhead LV and HV network (km)	Islands connected by subsea cables	Number of diesel generation stations	Distributed generation added to network ED1 (MW) over MEAV
SHEPD	24,700	59	7	0.15
Average DNO licence	16,600	Less than 1	None	0.09

Source: Company Specific & Regional Factor for RIIO-ED2 – Oxera 2021

The low population density means the density of our workforce is also low. To fix a fault, one of our colleagues will typically have to travel 30% longer than for an average sparsity DNO to get to the fault, quite possibly travelling part of the way by ferry (ferry crossings and frequencies are massively impacted by weather (storms), which often cause network faults). On average, our staff spend 102 minutes of driving per job.

To ensure security of supply for island communities, we currently own and operate seven Distributed Embedded Generation (DEGs) sites - small power stations that run on diesel - relying on them to support the network if the subsea cables supplying the islands are on an outage or have faulted.

The nature of the region means that building network resilience across this area is more complex compared to other networks; what works elsewhere does not always apply here. Some examples of the different challenges and greater complexity faced include:

- **The need for additional engineering assessments** to overcome design challenges due to the rocky coast lines specific to Scottish islands.
- **Remote locations** making engineering site visits and stakeholder engagement sessions a greater challenge due to durations out of office and associated cost. The general transport of equipment and materials to sites also presents a logistical challenge given many roads, bridges and ferries are unsuitable for carrying our equipment.
- **Tidal constraints and weather windows** for performing operations imposing restrictions on working windows in remote locations, or simply limiting when we can access a given island.
- **More regulatory requirements**, for example the need for a marine licence for all non-fault repair projects and environmental restrictions on our operations due to breeding birds and sea life. Further wayleaves are increasingly required for subsea projects due to the use of agents by local landowners. This adds time and cost to projects.

A relevant pertinent example is the local public roads on our current project at Carradale are not large enough to transport our Horizontal Directional Drilling (HDD) rig to site. This has meant paying an additional £77,000 to gain site access via a private road.

Similarly, when considering future needs, there are multiple cable and power station permutations possible in Orkney, but all will be subject to wider whole system solutions such as the transmission solution approval. Such permutations are even more challenging in the Outer Hebrides with the added complication of inter-island constraints. On the Inner Hebrides, there are difficult trade-offs to be made between having more subsea cables or more innovative solutions for back-up supplies.

The Shetland Islands

The North of Scotland also includes the Shetland Islands where we are working with Ofgem and stakeholders to deliver an electrical connection at the lowest cost to consumers, whilst maintaining

security-of-supply continuity. The Shetland delivery team will continue to engage with Ofgem and stakeholders, providing regular bilateral updates as key project milestones are achieved.

SSEN's RIIO-ED2 plan for the North of Scotland

Building on our experience of RIIO-ED1

We have learned and applied the lessons from RIIO-ED1 in designing our plan for RIIO-ED2. Namely:

- **Improving our asset data:** while we were already collecting data on our subsea cables, we have invested significantly across our business and implemented IT transformation during RIIO-ED1, which has improved our systems and processes for asset data, meaning it is accurate, timely and statistically significant. This has provided us with the best condition information available for a wider range of assets, in addition to subsea cables, when determining the programme for RIIO-ED2.
- **Working closely with a wider range of stakeholders:** to understand their needs, the impact of investments and future priorities to inform our plan.
- **Having a solid evidence base:** to justify the replacement of cables, we have carried out extensive optioneering and cost-benefit analyses against credible scenarios and continue to develop this evidence base.
- **Taking a proactive approach:** we have adopted a “balanced whole system” stance to consider a significant number of cables for proactive investment alongside a proposed Uncertainty Mechanism to lower overall costs to consumers and meet stakeholder needs.
- **Having a credible plan for delivery:** to mitigate risks around the availability of materials, manufacturing slots and installation vessels, we have plans to secure these under annual contracts and manufacturing capacity overseas.

Our strategic approach

Scotland has set a legally binding 2045 net zero target, five years ahead of the rest of the UK. It can only achieve this by accelerating electrification. Therefore, greater investment is required in both network capacity and its reliability to facilitate decarbonisation and support an ever-increasing reliance on the electricity network.

The North of Scotland electricity distribution region is critical for meeting both the UK and the Scottish governments' net zero targets.

- Our remote island communities are green energy hubs which will enable the UK to meet its carbon targets. Investment decisions today can help unlock that potential.
- Current diesel solutions that secure supply for today's customers are the largest source of controllable carbon emissions on our system. By challenging and then changing these network solutions, we can eliminate these emissions for future generations.
- A reliable electricity supply will become increasingly more critical for remote communities as we move to alternative low carbon technologies. Our investment decisions today need to secure that future for our customers.

The Scottish Government has recently announced the Carbon Neutral Islands project that will also require the network to be involved. The plan has identified six islands (Hoy, Islay, Great Cumbrae, Raasay, Barra and Yell) to move to be carbon neutral by 2040.

In addition to meeting net zero targets, we have sought to meet our stakeholders' calls for greater capacity as the level of renewable generation increases. The Distribution Future Energy Scenarios (DFES) analysis envisages for the North of Scotland:

- Far more homes relying on electricity for heating than the Great British average of 11% (over a quarter of homes (26%) in the licence area are already heated via electricity).
- A shift to greater use of heat pumps. Heat pumps are already used to heat 3.1% of homes in Northern Scotland, significantly above the GB average of 0.6%
- In line with Scottish Government policy targets, a significant number of properties will switch their heating technologies to low carbon alternatives by 2030, under the Consumer Transformation scenario. This translates to approximately 250,000 homes and approximately 21,000 non-domestic properties operating a type of heat pump by 2030.
- The number of electric vehicles registered in the North of Scotland licence area also increases significantly in all scenarios by 2030. This ranges from approximately 100,000 under the Steady Progression scenario to just under 330,000 under Leading the Way. This equates to a range of approximately 500 MW to 1.6 GW of electric vehicle charging capacity by 2030 across these two scenarios.

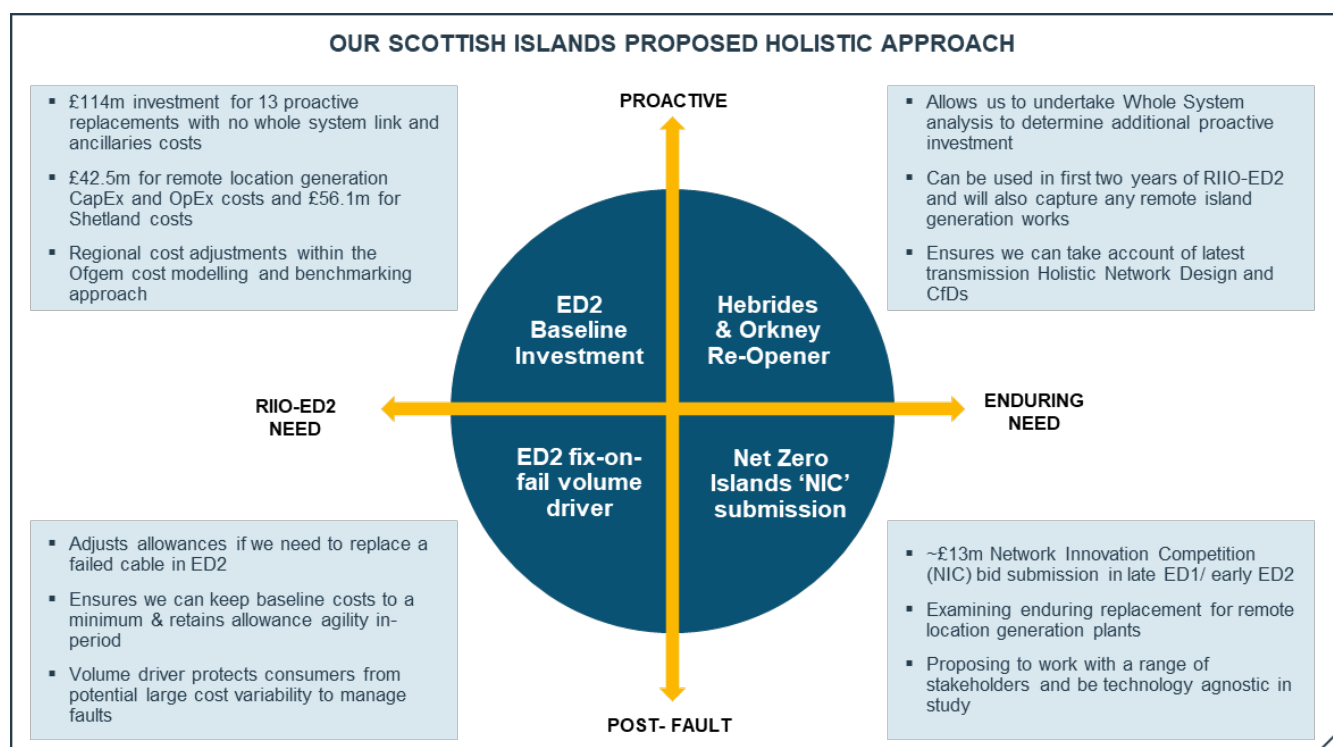
Other potential demand-drivers could include the region receiving funding from the £100m Island Growth Deal boosting demand for housing and commercial sites, and the decarbonisation of the islands' ferry network.

Our submitted business plan for the North of Scotland set out a baseline investment forecast of £212.5m to meet the above net zero objectives. This includes investment in subsea cables (£114m covering High Value Projects (HVP) asset replacement, inspections, faults, repair and maintenance, property and STEPm), ancillary cables, distributed embedded generation (£42.5m) and £56m for pre-construction and post-construction of the new transmission link and connection of the Shetland distribution and transmission networks. The certainty of need for these investments is clear, was well evidenced in our Engineering Justification Papers, and is stakeholder supported.

Our plan for North of Scotland involves adopting a proactive approach to managing the risk of subsea cable failure, recognising the environmental cost of faults (running diesel power stations) and the increasing reliance on electricity as customers principle or sole energy vector.

Our RIIO-ED2 plan is summarised below.

Figure 2: A holistic 'whole system' approach for RIIO-ED2



An example of the whole system approach we continue to take is the Net Zero Island Project submitted to the 2022 Network Innovation Competition on 1st August 2022 (decision expected from Ofgem in Oct/Nov 2022).

Net Zero Island Project

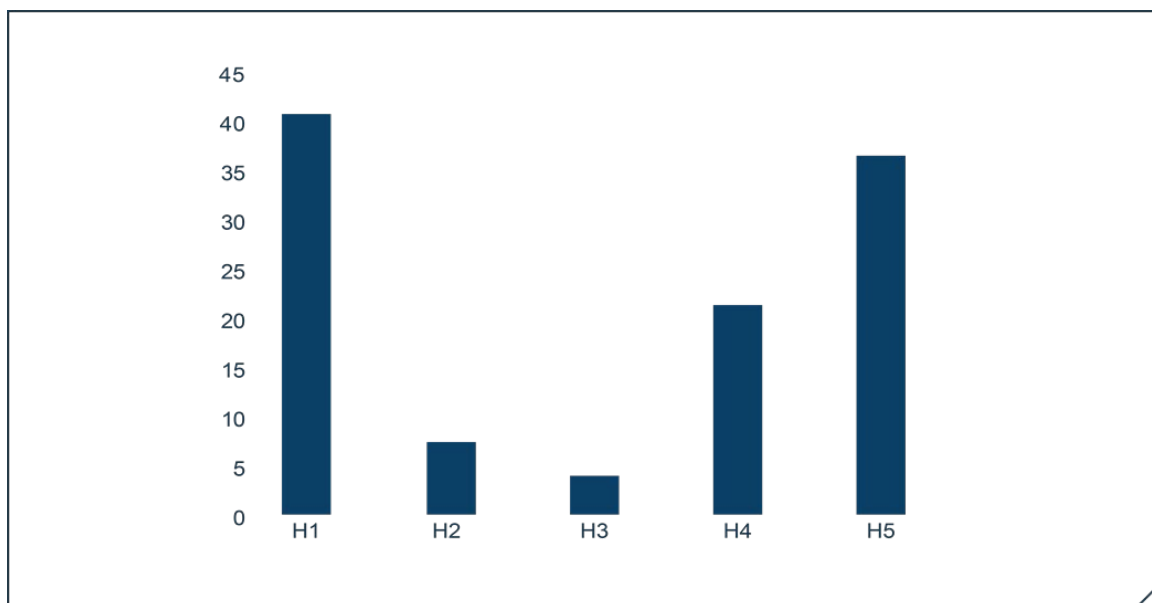
The project seeks to identify and demonstrate sustainable and commercially viable Whole System options to eliminate the use of carbon intensive diesel generation for maintaining supplies to our remote island communities in the North of Scotland. This is a pressing need, essential to allow SSEN to meet its Science-Based targets and capable of accelerating local decarbonisation ambitions.

There is no readily available low carbon solution to replace the use of diesel generators for maintaining supplies over long durations. The Net Zero Island Project will take a structured approach to identifying an alternative, whilst engaging and supporting our wider Scottish Island Strategy, the Scottish Government and local Island Strategies. The project will include, among other activities, working with other innovation programmes to identify emerging long duration energy storage technologies as well as mobilising demand side options to support resilience, and identifying the likely viable options from a technical, economic and sustainability perspective, ensure alignment with the Hebrides and Orkney re-opener.

To assist Ofgem in their understanding of this North of Scotland strategy, we set out below some key points which must be considered:

- There are 36 subsea cables within our portfolio at HI5 where there is clear evidence that they are at risk over the period of RIIO-ED2 into early RIIO-ED3. All these cables have a similar risk profile. This is shown below.

Figure 3: Count of assets by HI scoring by the end of RIIO-ED2 with no intervention



- Our strategy is to undertake proactive replacement of 13 of these cables. These have been prioritised because doing so will maximise the benefit to consumers (in terms of monetised risk) and allow us to profile our work across RIIO-ED2 & RIIO-ED3 so that we can ensure deliverability. This is a programme of work that we need to commence at the start of RIIO-ED2 following feedback from our supply chain, and to have confidence in deliverability. Current data shows we expect to have a minimum of 43 subsea cables (assuming 13 are replaced in RIIO-ED2) classified as HI5 by the end of RIIO-ED3. SSEN cannot allow an increasing 'bow wave' of asset-replacement projects to be pushed into future price controls.
- Our cost base for RIIO-ED2 subsea cable projects has been amended to reflect the inherent economies of scale present when delivering longer length projects. All our CBA reflect our cost base subdivided into three length categories: 0-3km (£1,501,500/km), 3-20km (£862,893/km) and above 20km (£705,405/km). The rates also recognise the consistency and fixed nature of project mobilisation and demobilisation costs, reflected in a fixed-cost element per project (£500,000). All cost base calculations and unit rates are based on historic costs from RIIO-ED1. The above rates do not reflect the significant increase in installation project unit rates being experienced (increased unit rates due to reduced vessel availability) as a result of global energy price increases since March 2022.
- Given their risk profile, we have sought funding in our baseline allowance to replace all 36 cables classified as HI5. However, we have not taken this approach because:
 - for five additional cables, we want the opportunity to undertake a whole system assessment before committing to a solution,
 - for other cables, we cannot be certain of the work that will be required or would like to maximise the asset value, and consumers should of course only pay for replacement work undertaken at the end of the asset life.
- Therefore, the effectiveness of our strategy for managing subsea cables depends upon having both funding for proactive replacement as well as access to the two Uncertainty Mechanisms (the Hebrides and Orkney Whole System re-opener and the "Fix-on-Fail" volume driver). This strategic package maintains resilience at the least cost to consumers. Not only does this avoid customers paying for work that is not required, but it also means we can minimise the cost of replacement work; by having a baseload of planned work we can contract for the required resources, and in

doing so we can retain access to staff, materials and vessels as and when an additional need arises.

We welcome Ofgem's agreement to the Hebrides and Orkney Whole System Uncertainty Mechanism (HOWS UM), but on its own it is only of limited value in helping us manage the replacement of our subsea cables. Unless the HOWS UM is accompanied by the "Fix-on-Fail" volume driver, then the only realistic way for us to manage the risk of subsea cable failure is to be provided with baseline funding for the replacement of all 36 cables. To be clear, this is not our preferred approach, and we encourage Ofgem to consider our subsea cable strategy as a holistic package.

Ensuring deliverability

We have demonstrated during RIIO-ED1 our ability to meet our commitments. For example, we proactively replaced 69.53km of subsea cable assets, with a further 21.38km to be replaced before end of RIIO-ED1. This is a total of 90.91km replaced against a commitment of 85.1km.

In addition, we have reactively replaced 75.64km of subsea cable assets under faults, which included two of our longest cables - Pentland Firth East (36.2km) and Skye-Harris (32.14km).

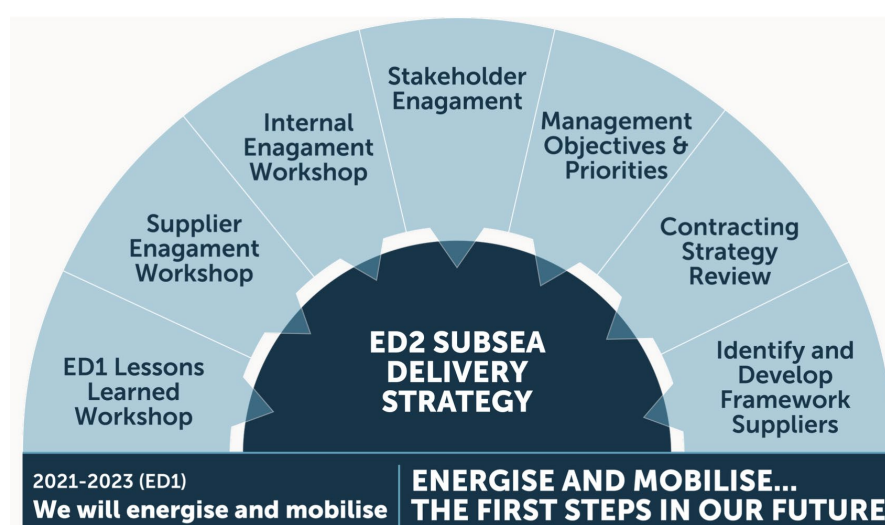
We propose to manage risk within RIIO-ED2 by balancing between the baseline and UMs. We are consciously not putting everything in the baseline so that we can do further whole system assessments and so we minimise costs to consumers by only replacing certain cables when they fail. Therefore, our baseline is the highest priority cables for replacement.

We have continued engaging with stakeholders and supply chain following our submission in December 2021 to ensure transparency, but also to ensure the deliverability of specific asset bundling and sequencing. It is also important our supply chain partners have the ability, expertise and capacity to deliver in accordance with our plan, on top of an already buoyant oil and gas industry and renewables sector.

Ofgem's DD unit rates for all NoS deliverables are undeliverable and do not reflect the actual costs that we are likely to incur. Our supply chain engagement has continuously advised that 2024 and beyond is going to see a significant shortage of subsea installation assets (vessels / equipment) as well as competent personnel. Commercial terms and conditions (day-rates) have already increased by over 30% in the first eight months of 2022. Therefore, it is critical we confirm our proactive asset replacement strategy to define our requirements to our supply chain and secure installation assets.

Our RIIO-ED2 North of Scotland subsea delivery strategy has involved inputs as follows:

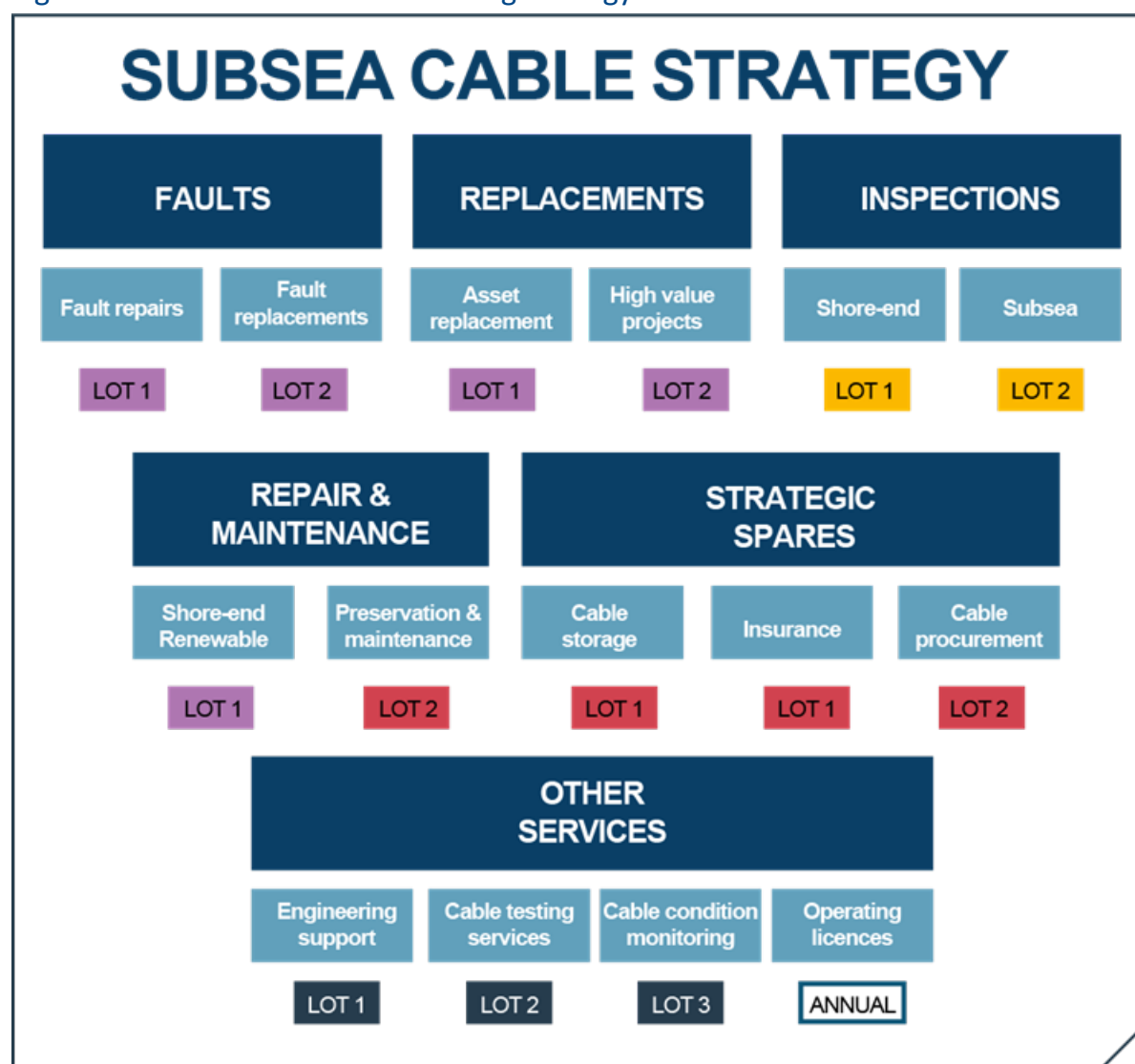
Figure 4: RIIO-ED2 subsea delivery strategy



As part of the above process, regular supply chain engagement has allowed us to develop efficiencies and good practice with existing suppliers; it has also provided an opportunity to identify new suppliers to balance our delivery risk, whilst also ensuring high standards and commercial value. Additional advocacy engagement has also supported this approach – see Annex 1 Advocacy for more information. The buoyant subsea market has resulted in many changes to our framework suppliers. As a result, we have identified new suppliers to supplement our existing experience and help balance our ability to deliver both proactive and reactive installation projects. Without having proactive asset projects, it becomes very difficult and expensive to obtain slots on a vessel to perform reactive campaigns under fault conditions.

We are proposing a new framework strategy, shown below in Figure 5, to deliver multiple benefits during RIIO-ED2. By identifying packages of work ‘lots’, it allows us to engage with a wide variety of specialist suppliers. Having several supplier options to deliver each ‘lot’ of work will ensure we can deliver our proposed volumes, but also contract on mutually beneficial contracting terms while delivering consumer value and efficient operations.

Figure 5: RIIO-ED2 subsea contracting strategy



We are particularly keen to finalise our proactive asset placement projects and subsea cable inspections requirements, which will enable us to commence early engineering and book vessel slots at competitive

prices for the early years of RII0-ED2. In addition, our proposed High Value Projects will require an extended project life cycle to protect consumers and commence site surveys, and hence early planning and booking of cable manufacturing slots is critical.

The Opex and Capex work associated with our remote embedded generation sites both require feasibility studies and detailed engineering before any long-lead procurement commitments can be placed. It is essential that the engineering commences as soon as possible, to secure critical components and spares before availability and lead times introduce significant delays to our deliverability. These delays, in turn, jeopardise the benefits of increased capacity, reduced running costs and reduced emissions.

The deliverability of our Shetland plan remains in accordance with the Ofgem bilateral held on 1 August 2022. There are a number of tendering activities and project milestones currently under way and hence a further update will be provided to Ofgem via a bilateral session in September or October 2022.

Ofgem's Draft Determination

Ofgem's Draft Determination (DD) makes significant reductions to our requested baseline. Instead of the £212.5m requested in baseline funding, we have been provisionally allocated £164.2m. Ofgem also rejects our Fix-on-Fail Uncertainty Mechanism. Not only does this put proposed investments at risk, affecting net zero targets, it ignores submitted stakeholder evidence on customer and community priorities gathered during eight specific events involving more than 214 stakeholders previously shared with Ofgem. Further DD feedback from those stakeholders is included within Annex 1 – Advocacy.

Ofgem's DD would condemn the North of Scotland to an unreliable and insufficient power network. The DD fails to recognise the challenges associated with operating across Scotland's unique geography and Ofgem has ignored evidence provided on issues SSEN, its stakeholders, and customers face.

Ofgem's DD does not acknowledge the specific factors that make the North of Scotland different and necessitate a bespoke approach, and that certain investments should be placed in the baseline or not covered at all. As one stakeholder from the Hebrides told us:

"There needs to be a unique offering for each island, due to the unique characteristics of each one."

While we welcome parts of the DD package, such as the Hebrides and Orkney re-opener, the overall DD fails to recognise the challenges associated with operating across the region's unique geography and ignores evidence on issues our stakeholders and customers face. Ofgem has failed to recognise our clear shift towards an approach that takes an appropriate balance of baseline TotEx and Uncertainty Mechanisms to deliver the lowest cost to consumers, while maintaining reliability and delivering net zero. The approach in the DD also runs contrary to previous acknowledgement from Ofgem that a more strategic approach was required compared to RIIO-ED1.

Stakeholders' feedback from our engagements since June 2022:

Various stakeholders do not believe that Ofgem has adequately recognised the unique nature of the north of Scotland in its Draft Determinations. These stakeholders are clear that the characteristics and requirements of the North of Scotland, and in particular our Scottish Islands, require a bespoke and tailored approach, and are therefore disappointed that Ofgem has reduced subsea cable baseline allowances overall for the Scottish islands and has not committed to replacing the existing Skye-Uist cable.

Scottish islands stakeholders expressed serious frustration at Ofgem's cuts to subsea cable allowances and the gap in previous rhetoric and recent delivery when it comes to a longer-term strategic approach for subsea cable asset management.

Stakeholders on the Western Isles remain exasperated by Ofgem's decision to reject SSEN's funding request for the Skye-Uist cable and the 'fix-on-fail' Uncertainty Mechanism. They were at pains to highlight the damaging effects subsea cable failures can have on homes, businesses, renewable generators and the environment, noting that standby diesel generation led to over 90,000 of CO₂ being emitted following the Skye-Harris fault and the inability to export resulted in c.£2m in lost community funding revenue.

We note with regard to our subsea cable repair Uncertainty Mechanism, the Customer Engagement Group (CEG) in its report *“accepts that the UM will allow SSEN to speed up the replacement of a failed cable to restore resilience and reduce back-up generation sooner than would otherwise be achieved. We believe this is in the interests of consumers.”*

The CEG further notes on investment costs and subsea cables specifically:

“Subsea cable investment costs are a significant percentage of the total investment proposed. There is an Uncertainty Mechanism proposed for costs associated with major subsea cable failures. This approach is supported with insights from stakeholder engagement. It is a pragmatic approach to address major failures given the lumpy and unpredictable nature of these costs. There is good use of a Whole System approach being used to consider greater use of flexibility services and real-time monitoring.”

Ofgem’s benchmarking process fails to acknowledge the specific additional costs associated with operating in the north of Scotland, for example, the obvious costs of maintaining the electricity network in geographically remote, large and sparsely populated regions. For example, Ofgem’s benchmarking process and DD have only allowed for 5.6 km of LV cable for SHEPD over the course of the RIIO-ED2 price control. This is obviously wrong and is a material error.

To summarise, Ofgem has wrongly based its proposals on the following assumptions:

- The volume, cost and design of proposed subsea cable works not being deemed appropriate
- The risks of subsea cable failure should be managed from within baseline allowances on a proactive basis rather than through Uncertainty Mechanisms
- There is no material change in risk between RIIO-ED1 and RIIO-ED2
- There being no material Company Specific Factor claims for the region that would necessitate a different approach to costs.

In the next four sections, we set out how Ofgem has made material errors, taken an inconsistent approach and/ or not fully considered evidence when setting out its determination of our baseline TotEx and Uncertainty Mechanisms. To support resolution, we have incorporated proposed recommendations.

Volume, cost and design of planned subsea cable works

Detailed information provided in:

Business Plan	Annex 8.1 – Scottish Islands Re-submission letter – April 2022
Consultation questions	SSEN-Q8 SSEN-Q9 SSEN-CORE-091 SSEN-CORE-092 SSEN-CORE-094 SSEN-CORE-096 SSEN-CORE-099
EJPs	458 – Skye to South Uist (Unjustified) 403 – Mainland to Kerrera 2 (Unjustified) 441 – Jura to Islay (Justified) 395 – Coll to Tiree (Justified) 331 – Hoy to Flotta (Unjustified) 335 – Loch Long (Dornie) (Justified) 338 – Mull to Iona (Justified) 394 – Orkney to Shapinsay (Justified) 405 – Laxay to Kershader 2 (Justified) 457 – Loch A'Choire North (Unjustified) 333 – Loch A'Choire South (Unjustified) 414 – Kintyre to Gigha (Justified) 404 – Mainland to Kerrera (Unjustified)

In April's re-submission of our business plan, we proposed to proactively replace or augment 13 subsea cables with the greatest needs case. These were made up of 12 Asset Replacement (CV7) schemes and a high value project (CV25) enabling the strategic installation of a new cable between Skye and South Uist (South Route). This reflected our agreement with Ofgem to remove five cables from our original business plan so that we could consider their requirements in the context of a 'whole system' assessment. Ofgem has confirmed that if required, funding for these could be enabled through the HOWS UM.

The cost of our subsea investment baseline proposal was £114m. Ofgem's DD allowed us £82.1m. Over the five-year period of RIIO-ED2 this leaves us with a shortfall of £32m for subsea cable investment.

In the DD, Ofgem recognised the “*need for the proposed investments*” but highlighted that they would “*benefit from further individual justification, such as inspection and test data, how the timing of investment has been chosen, detailed costs, and programme information for individual projects. The portfolio of projects also needs to be reviewed to take account of dependencies between individual circuits and to provide an overarching delivery strategy to better clarify the benefits and economies of scale related to projects being undertaken together.*”

Our strategy for proactive investment is to prioritise those cables that are 1) critical to maintaining the security of supply to consumers and customers on the islands, 2) where the certainty of need to intervene is highest, and 3) where replacement will achieve biggest benefit to consumers (in the form of lower interruptions and minutes lost).

Without proactive intervention these cables will fail at some point in the near future. By intervening in RIIO-ED2, we will reduce the long-term monetised risk associated with subsea cables by ~£35m (an update on the value of ~£32m in our final business plan to align with our April 2022 re-submission), relative to the case without proactive intervention in subsea cables. Ofgem’s DD significantly reduces the monetised risk improvement from proactive subsea cable replacement to ~£1m. This is a result of Ofgem’s direction that we should replace fewer circuits compared to our business plan. This introduces greater risks to the priorities for local communities, including potentially higher constraints on renewable generation associated with a cable failure, and greater ongoing dependency on back-up diesel generation.

Ofgem’s DD will mean that this investment will either be made on a reactive basis (as subsea cables fail) or be pushed back into RIIO-ED3. In either event, the cost of the replacement (which will be required in any event) is likely to increase. This is either because we are not able to plan and engage early with our supply chain, we’ll be a ‘distressed buyer’ or because we will face a bow-wave of work in the future period that will present a significant deliverability challenge. Added to that is the ever-increasing challenge of the renewables sector expanding globally and driving market rates higher due to demand outstripping supply.

This is not an acceptable outcome. Ofgem has not provided evidence that would justify the rejection of our proposed investment and have disregarded the needs of our stakeholders on the islands, contrary to its statutory duty to have regard to the needs of existing and future consumers.

The needs case for subsea cable intervention in RIIO-ED2 is asset data-led; refined and iterated by overlaying the industry standard risk management methodology with bespoke risk modelling and cable-specific cost benefit analysis. In the supplementary information provided to support our Engineering Justification Papers (EJPs - see Appendix A) we have provided further information of the nature requested by Ofgem in the bilateral meeting on 28 Jul 2022 and optioneering we have undertaken for each scheme.

In addition, comprehensive information on Horizontal Directional Drilling (HDD) has been provided in response to Ofgem’s Engineer Hub (letter dated 5 Aug 2022 issued by Niall McDonald) to further justify the challenges and risks we face implementing an HDD subsea cable replacement solution. Appendix A also addresses feedback Ofgem raised in the response to SSSEN 030 Supplementary Question.

We have targeted proactive invention in certain cables so we can be confident in our ability to deliver the overall subsea cable programme. We anticipated that Ofgem would put weight on this

consideration, as in the final determinations for RIIO-ED1 and throughout the course of this period, Ofgem has raised concerns with the deliverability of our proposed cable works.²

Recognising Ofgem's challenge, we have built out our team and updated our strategy to further evidence our ability to deliver in planning for RIIO-ED2 and beyond, and we have carefully considered how we can best achieve our overall programme over an extended period. We have consciously aimed to not overreach in our ask for RIIO-ED2 and have prioritised those cables that are both essential and deliverable. Operating in conjunction with both the HOWS UM and the "Fix-on-Fail" volume driver, we are confident that we will be able to scale up our activity throughout the period, but only when required. We also have the support of our supply chain following extensive engagement over the past 12-14 months.

We have raised supplementary questions to Ofgem to get a better understanding of which costs have been disallowed and why. These include a request for Ofgem to explain why the cable replacements at Loch A'Choire North and South have been classed as unjustified due to the association with the Mainland-Kerrera cable (which was also viewed as unjustified).

To clarify, and as explained in Appendix A, the cables at Loch A'Choire are not on the same electrical circuit as the Mainland-Kerrera cables; and while the cables at Loch A'Choire and Mainland-Kerrera have the same proposed delivery year, they are separate projects - although we would of course seek out synergies in their delivery. The assessment of the Mainland-Kerrera should in no way impact on the assessment of the Loch A'Choire cables.

We also emphasise that any subsea cable works that need to be considered in the context of a 'whole system' solution have been removed from our request for baseline allowances. We expect the consideration of these projects to be assessed through the HOWS UM. We highlight this point as Ofgem's engineering assessment appears to have already formed a premature view on the following cable replacement projects:

- Skye – Uist (North Route): 'Unjustified'
- Pentland Firth West: 'Justified'
- Mainland Orkney – Hoy South (3): 'Justified'
- Eriskay – Barra 2: 'Justified'
- South Uist – Eriskay: 'Unjustified'

All of these cables have been removed from our ex-ante baseline request through the 29 April 2022 re-submission. We expect these requirements and costs to be re-evaluated should they be submitted through the HOWS UM, given Ofgem's statutory duty not to pre-judge proposed costs before they have been submitted for evaluation.

"Fix-on-Fail" Uncertainty Mechanism

Detailed information provided in:

² In RIIO-ED1, we applied for additional funding through the subsea cable reopener. Ofgem did not allow the full 95.2km protection allowance requested as they did not have confidence in our ability to replace 16 cables by the end of the price control. As detailed in this response, 90.91km were proactively replaced in ED1 against a commitment of 85.1km and 75.64km were reactively replaced.

Business plan	Annex 17.1 – Uncertainty Mechanisms Re-submission Letter – April 2022
Consultation questions	SSEN-Q8 SSEN-Q9 SSEN-Q10
EJPs	N/A

In our business plan, we proposed a new Uncertainty Mechanism (UM) to enable us to respond swiftly should there be a failure to any of our subsea cables. This mechanism would operate as a volume driver. This volume driver accompanies the HOWS UM and, in combination with baseline allowances, the two mechanisms are essential to support the delivery of our subsea cable strategy.

Ofgem proposed to reject our proposed “Fix-on-Fail” Uncertainty Mechanism because they considered that we are *“best placed to manage risk relating to their subsea cable portfolio on a proactive basis, underpinned by a robust understanding of the health of these assets.”*

Restoring subsea cable supplies quickly and cost-effectively is critical. This minimises the negative impacts on consumers disrupted power supplies and reduces the need for backup remote generation. Currently when faults occur, diesel generators are often required to bring the remote areas back online and local renewable generators are disconnected as the network is down. The timely replacement of subsea cables is therefore vital not only for customer service, but also in supporting net zero targets and minimising disruption to renewable generators in our island communities (which in turn impacts their profitability).

As the only DNO with a material number of subsea cables, SSEN is exposed to more risk in these assets failing. The marine environment in which subsea cables are located can destroy cables quickly, as the cable is subjected to several external factors which standard underground cables are not. We fully accept our responsibility to manage this operational risk and we have identified at least 36 cables where there is a reasonable probability of failure by the end of RIIO-ED2 and where we could justify seeing baseline funding for their replacement in RIIO-ED2.

Having baseline funding for the replacement of all 36 cables would enable us to take proactive steps when we can more accurately predict the likelihood of a failure. But this would be a blunt approach to managing risk: it would increase costs for consumers if the need for the work does not materialise or can be delivered at less cost than forecasted.

Instead, our proposed strategy for RIIO-ED2 is to manage this risk on both a proactive and targeted basis, and through the utilisation of either the HOWS UM or “Fix-on-Fail” Uncertainty Mechanisms. In our view this strategic package achieves a much better outcome for consumers.

This approach is also broadly consistent with the approach taken by Ofgem in the RIIO-T2 Final Determinations for SSEN Transmission. Here, Ofgem agreed to a re-opener for subsea cable replacement if a cable faults and cannot be repaired. Ofgem has not given any justification why the equivalent cables in SSEN’s distribution portfolio have a lower likelihood of failing.

While it is probable that other cables we have identified as being at risk will fail in the near future, there is a reasonable likelihood that not all of them will, at least not within the RIIO-ED2 period. Equally, other cables that currently appear healthy may deteriorate unexpectedly and quickly. This simply reflects the reality that the forecasted likelihood of failure across a group of assets may not result in an equally distributed occurrence of failure for assets in that group.

Our experience in RIIO-ED1 illustrates this uncertainty. At the start of RIIO-ED1, we anticipated replacing 85.1km of subsea cables. By the end of the period, we will have proactively replaced a total of 90.91km and reactively replaced 75.64km under faults. Importantly, many of the cables we have ended up replacing were not among those that we had expected to at the start of the period. And some of the cables that were to be replaced have performed better than expected. Our understanding of asset condition is continuously improving, however there will always be a residual element of uncertainty in forecasting the likelihood of subsea cable failure in a narrow window of time. The UM will protect delivery of our RIIO-ED2 baseline commitments.

In Table 3 below, we show the Health Index (HI) score at the point of failure for cables that needed to be repaired or replaced in RIIO-ED1. This highlights that cables which may be young, or appear in good health, can still fail ahead of their anticipated end-of-life, which should be at around HI5.

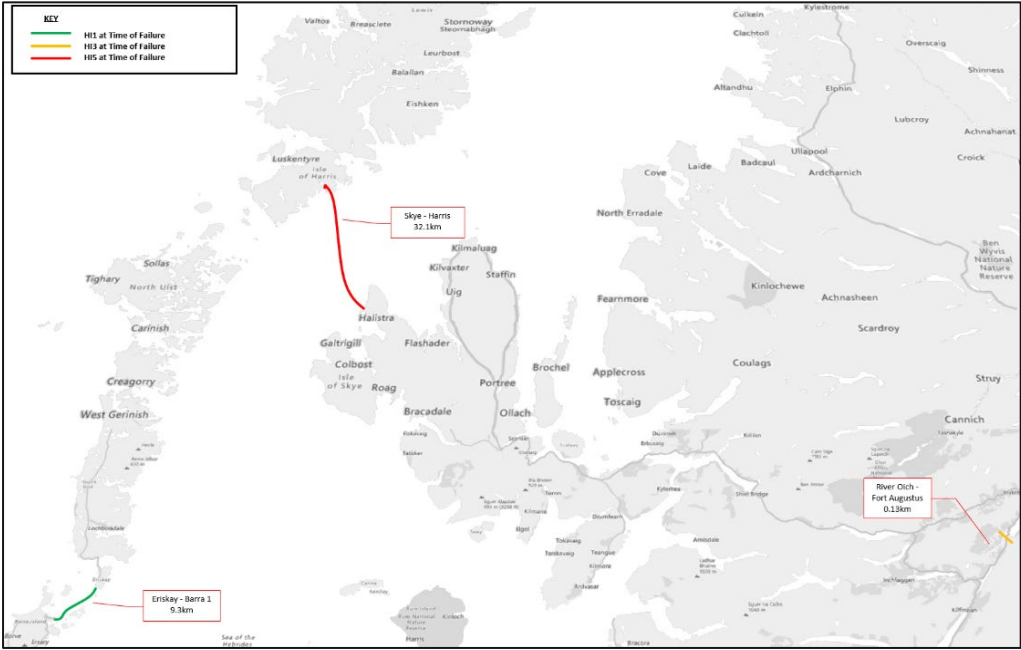
Table 3: RIIO-ED1 faulted cables and their associated HI at time of fault

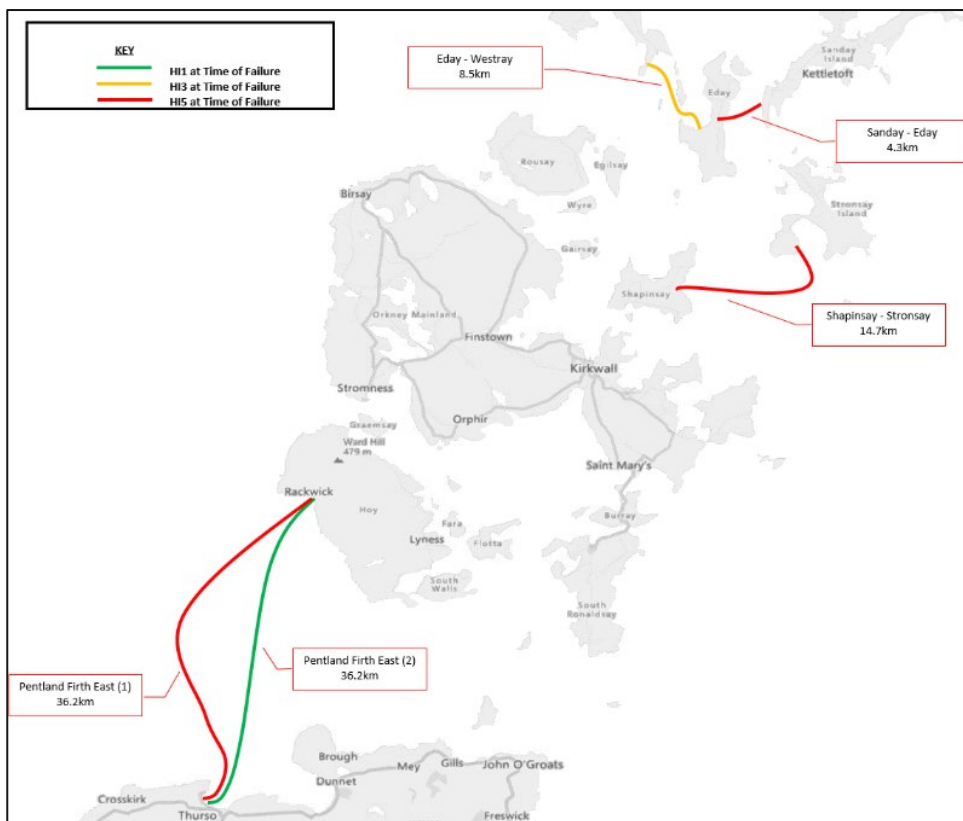
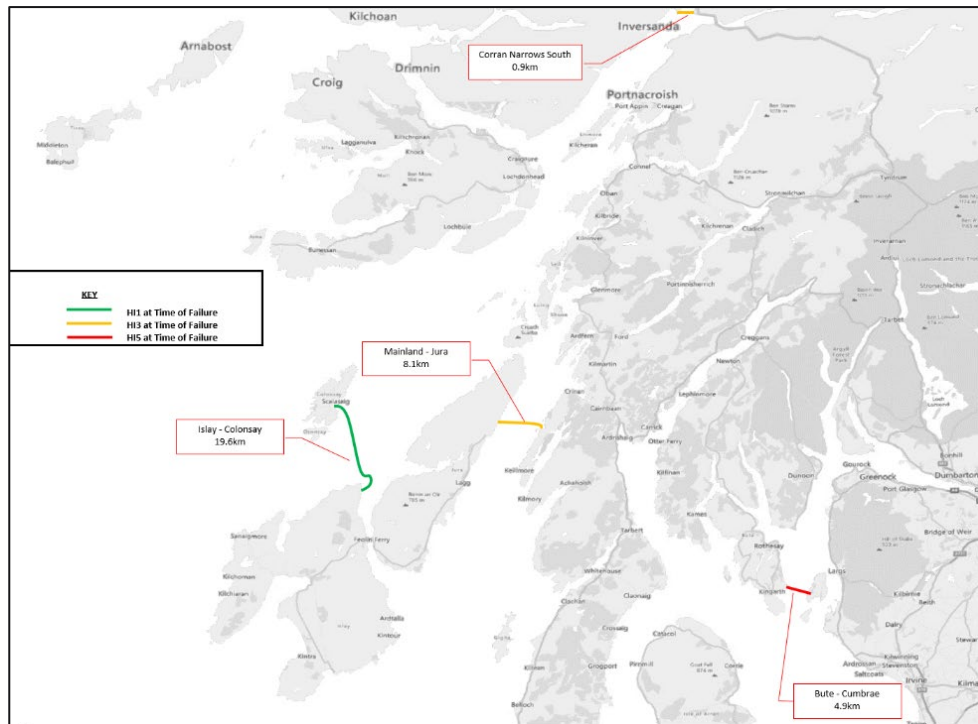
Cable	HI @ time of fault
Pentland Firth East (TS1)	HI1
Pentland Firth East (1)	HI5
Skye – Harris	HI5
Sanday – Eday	HI5
Eday – Westray	HI3
Mainland – Jura	HI3
Bute – Cumbrae	HI5
Corran Narrows South	HI3
Islay – Colonsay	HI1
Eriskay - Barra 1	HI1
Shapinsay - Stronsay	HI5
River Oich - Fort Augustus	HI3

Source: SSEN

Figure 6 below highlights the RIIO-ED1 faulted cables geographical locations. Reading left to right, the regions covered are Western Isles, Inner Hebrides, and Orkney.

Figure 6: Geographical location of RIIO-ED1 faulted cables





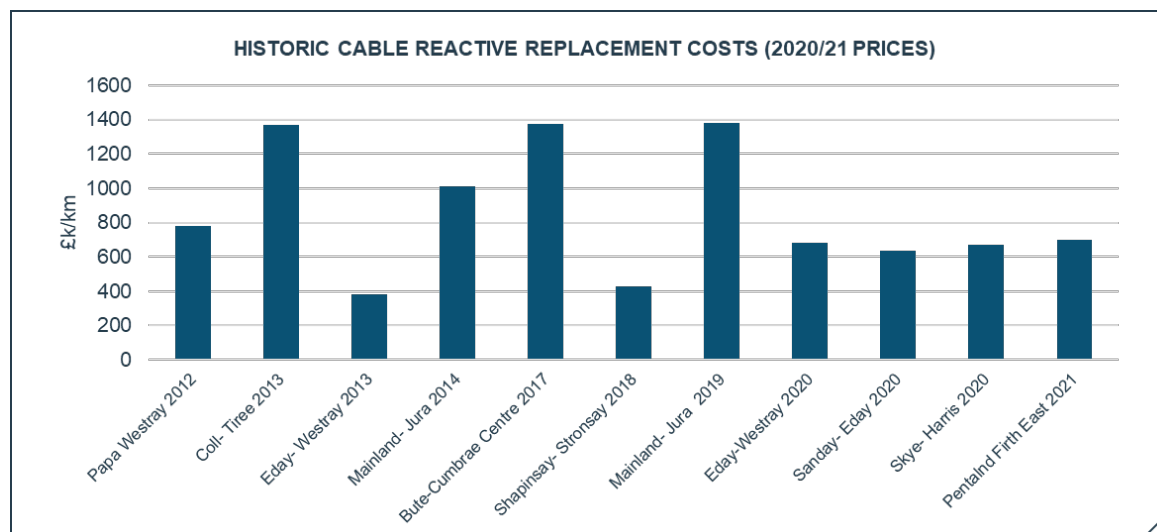
Ofgem appears to have misunderstood the basis of our proposals for an Uncertainty Mechanism. Although for the reasons given above, we may not be certain that all the cables in the group we deem to be at risk will actually fail in the RIIO-ED2 period, this does not mean that the likelihood of failure for each cable is set to zero, which is the unavoidable interpretation of Ofgem's position.

Our experience is also that the costs associated with subsea cable replacement can vary significantly depending on:

- availability of vessels, equipment and specialist personnel at short notice
- spares availability and shipping costs from outside the UK
- 'waiting-on-weather' costs: faults in winter can have longer lead times for installation windows
- competition for cables, crew and equipment
- requirement for subsea cable protection (burial) or subsea cable stabilisation
- stakeholder issues, consenting and statutory licence obligations.

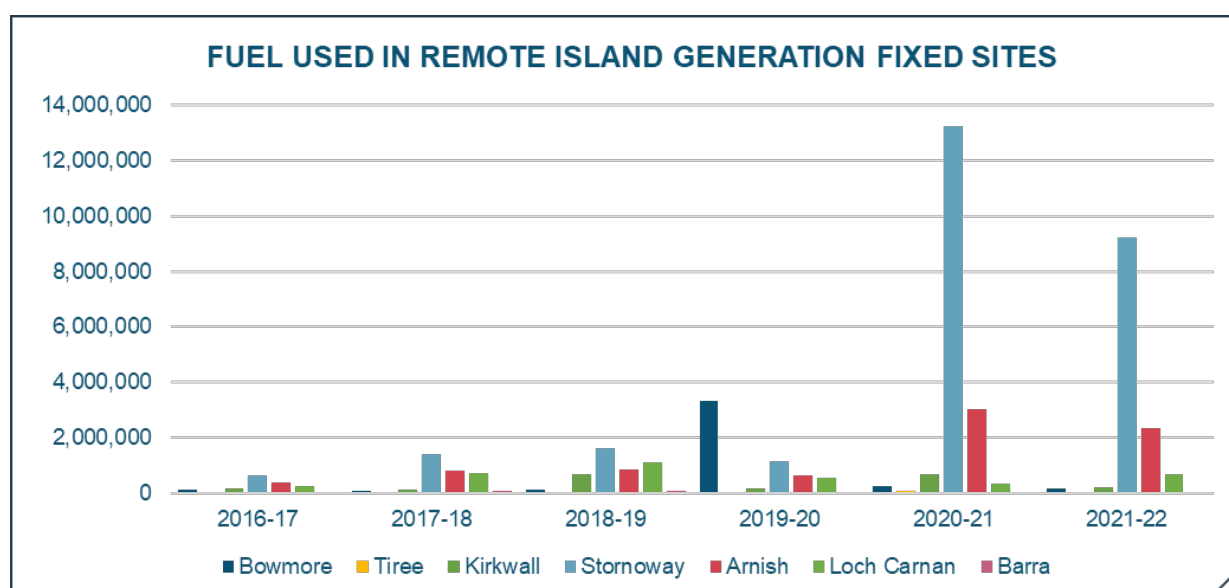
As well as driving the cost of replacement works, these factors can equally impact on the time taken to complete a replacement. This in turn will directly impact the amount and cost of fuel for back-up generation during an outage. Figures 7 and 8 below illustrate the type of cost variances that we have experienced in RIIO-ED1.

Figure 7: Historical subsea cable reactive costs per km



Source: SSEN

Figure 8: Historical remote island generation fuel costs during subsea cable fault



Source: SSEN

As a result of these uncertainties, we have proposed a volume-driver rather than a re-opener to offer consumers a protective hedge against fluctuations in unit costs, such as those seen above. Our unit cost is derived from historical averages, and this means that consumers are not exposed to the full cost of uncertainties that are outside our control.

In Annex 17.1 (Appendix 1) to our final business plan, we set out our approach to calculating a unit cost for a volume-driver. This proposal is the best means of managing this risk and mitigating administrative overheads for both ourselves and Ofgem. We would be open to further discussion with Ofgem on any questions or concerns they have with our proposed mechanism or analysis. Equally, we would be happy to explore with Ofgem, the merits of an alternative method to enable a speedy response to subsea cable failures (such as a re-opener).

Ultimately, however, without a mechanism we will have severe limits on our ability to deliver our overall strategy for the North of Scotland and wider RIIO-ED2. If we need to react to unforeseen cable failures, there will be tough decisions and unwelcome opportunity costs to be made with less agility and lower allowances to work with. For example, sacrificing some of our funded baseline outputs to concentrate on resilience needs following a subsea cable fault.

Remote island generation

Detailed information provided in:

Business plan	Annex 8.1 – Scottish Islands Re-submission Letter – April 2022
Consultation questions	SSEN-CORE-083 SSEN-CORE-100
EJPs	345_SHEPD_ENV_BATTERYPOINT

We own and operate seven remote island generation power stations. In our business plan we proposed £42.5m on remote standby generation for our island communities. Further detail on the costs can be found within Appendix F – NoS Business Plan Data Tables. This was to ensure security of supply to

customers on these islands in the event of a planned outage or failure of a subsea cable, and in the absence of either wider reinforcement or a smart energy solution being available on the affected islands.

While the bulk of this work was for operational and maintenance costs (OpEx - £26.0m), we had requested £16.5m of capital expenditure to enable the replacement of two engines at Battery Point with more efficient plant, and the procurement of generation equipment at Bowmore to provide additional capacity and avoid the cost of mobile generation.

Ofgem proposed to reject the capital cost of this work because they considered that we had not demonstrated that *“the delivery risk is materially different in RIIO-ED2.”* We also understand that Ofgem may have disallowed these costs to ensure that they were not providing funding that could be used to improve our Interruption Incentive Scheme (IIS) performance.

Ofgem has misunderstood our requirement - there is no corresponding impact of this CapEx on our IIS performance. The funding we have requested is to replace two engines that are currently in use but fast approaching the end of asset life, and to improve the capacity and reduce the cost and emissions associated with mobile generation at Bowmore. This fully supports our commitment to the 1.5°C Science Based Target and will improve resilience to some of the worst- served customers on our network. Supplementary information has been provided within Appendix B – Remote Generation to assist Ofgem with justifying the associated EJP and provide specific details on the investment, and associated deliverability.

We request that Ofgem acknowledges this misunderstanding and reinstate these costs in its Final Determination.

Company-specific factor claims

Detailed information provided in:

Business plan	Annex 8.1 – Scottish Islands Annex 15.1 – Cost efficiency Annex 15.4 - Establishing an appropriate efficiency challenge Annex 15.7 - Company-specific and regional factors for RIIO-ED2
Consultation questions	N/A
EJPs	N/A

As previously stated in this Annex, we believe we are unique amongst other DNO's given the Scottish islands and associated sparsity of our North of Scotland network. In our business plan, (*adjusted for DD cost treatment changes*) we proposed that on an annualised basis £44.6m of company-specific factors associated with serving our unique Scottish region should be excluded from TotEx benchmarking. For the avoidance of doubt, these are not costs that we want added to our TotEx allowance, these are the proportion of our TotEx that should be subject to a specific regional cost assessment. In our view, these costs are unique to the North of Scotland. By not assessing these separately, Ofgem has failed to fulfil its statutory duty to take into account all relevant factors, including the unique geography of each licence area.

A detailed breakdown of all our company specific factor costs is included within Appendix F – North of Scotland Business Plan Data Tables - for ease of reference. To further support Ofgem's understanding and assessment of our annualised company-specific factors' costs, the following overviews have been prepared:

Overview 1: SHEPD Islands (excluding subsea cable) company-specific factor overview:

- 87% of GB islands greater than 5km² are located in Scotland – This is unique to SHEPD.
- Our licence condition states we must not discriminate in providing electricity access based on location which is outside management control.
- The impact of serving islands is not built into any other cost drivers so is incremental.
- Serving Islands account for 3% of SHEPD TotEx ask in RIIO-ED2 so has a material impact.

Our Scottish Islands company-specific factor claim is summarised in Table 4 below. The RIIO-ED2 request is in line with actual costs incurred in the RIIO-ED1 period and, except for the subsea cable delivery team, which was an additional allowance as part of the subsea cable re-opener in RIIO-ED1, the need case was accepted in RIIO-ED1 Final Determinations.

Table 4: Scottish Islands company-specific factor annualised

CSF in RIIO-ED1?	Detail	Annualised RIIO-ED1	Annualised RIIO-ED2	Rational: Additional Cost due to Islands
	Subsea cable team	1.0	1.5	Dedicated CAI Team of 23 WTE to plan / design / deliver subsea cable work. Cost based on average salary per role. In RIIO-ED1 the subsea re-opener was approved which included an indirect allowance.
Y	Flights, accommodation, and ferries	0.3	0.4	Travel and accommodation to Islands and inter-island. Ferries / flights / boat hire / accommodation. Cost based on actual trips / island accommodation. See later in Annex.
Y	Helicopters	0.1	0.1	SHEPD retains the services of helicopter companies which allow their remote networks to be assessed from the air following a storm, to identify points of damage. This is the cost for use of helicopters
Y	Deployed staff prior to forecast severe weather events	0.4	0.3	SHEPD needs to transfer additional staffing to the islands prior to forecast storm events to ensure that there are sufficient resources to deal with potential faults due to remoteness of SHEPD customers and cancellation of services due to weather. On average there have been >2 events p.a. where staff

				have been deployed, but the event has not materialised.
Y	Remote location generation opex (Gross Costs)	7.5	5.7	See previously in this Annex – Needs case accepted but cost for opex element only applied DD.
	QoS & NoSR - Remote location generation capex	0.4	3.3	
Islands excluding subsea Total		9.7	11.3	

Overview 2: SHEPD company-specific sparsity factor overview

- SHEPD covers 25% of GB landmass with just 2.6% of GB customer base – this is unique to SHEPD
- SHEPD's sparsity is outside of management control, though our aim is to mitigate the impact
- The impact of this sparsity is not suitably accounted for in any other cost-drivers so is incremental
- Sparsity accounts for 5% of SHEPD's TotEx ask in RIIO-ED2 so has a material impact.

Our company-specific sparsity factor claim is summarised in Table 5 below. The RIIO-ED2 request is in line with actual costs incurred in the RIIO-ED1 period and, except for load-managed areas which were not included in the RIIO-ED1 claim, the needs case was accepted in RIIO-ED1 Final Determinations.

Table 5: Scottish sparsity company-specific factor (CSF) annualised

CSF in RIIO-ED1?	Detail	Annualised RIIO-ED1	Annualised RIIO-ED2	Rationale: additional costs due to sparsity
Y	Property costs	0.3	0.3	SHEPD incurs higher property-related costs as there are an increased number of depots required to support the network and customers. On a per- customer basis, there is 1 depot per 25,000 customers in SHEPD's area versus 1 depot per 150,000 customers in SEPD area (representing an averagely sparse DNO). RIIO-ED1 spend is based on actual costs incurred for remote properties in excess of an average network - this equates to an average of £25k per depot. See later in Annex.
Y	Outposted staff	5.8	5.6	SHEPD requires additional staff costs compared with other DNOs due to the remote location, geography and terrain of our network. Please see later in Annex for technical and operational analysis.
	Longer driving times (unproductive time)	1.0	1.1	Due to the sparse and difficult-to-access network, SHEPD's workers

Y	Additional vehicles / fuel cost	0.8	0.8	spend more time driving compared to staff of an average network. This leads to unproductive time, as well as additional fuel and vehicle costs. See later in Annex.
Y	Private Mobile Radio (PMR) system and scanning telemetry	2.6	2.2	Maintaining and operating a Private Mobile Radio (PMR) network is necessary as remote areas of SHEPD's network are not covered by telecoms companies, and also allows staff to communicate during disruptions to the telecoms network where there is one. SHEPD must also use specialist scanning telemetry in its remote areas.
	Load-managed areas	0.4	0.6	Due to remote areas, SHEPD needs to use radio signals to manage electricity supply in order to manage load on the system, minimising risk of failure and maintaining network integrity. SHEPD is the DNO that is most affected by load-managed areas within its network, and currently, load management is applicable to 90,000 customers, equal to 10% of the customer base.
Sparsity Total		10.9	10.5	

Overview 3: SHEPD subsea cables company-specific factor overview

- Subsea cables are unique, in that they are material only to SHEPD.
- SHEPD's sparsity is outwith management control although we still propose for subsea cable spend to be assessed but based upon EJP/CBA evidence.
- The impact of subsea cable is not suitably accounted for in cost-drivers so is incremental.
- Subsea cables account for 9% of the SHEPD TotEx ask in RIIO-ED2, so has a material impact.

Our subsea cables company-specific factor claim is summarised in Table 6 below. RIIO-ED2 is broadly in-line with RIIO-ED1, except for additional costs included for strategic cable storage and subsea cable condition-monitoring software. Subsea cable inspections continue to be important to us, and they support our asset health data which is used to determine our proactive subsea intervention strategy.

Table 6: Subsea cables company-specific factor annualised

CSF in RIIO-ED1?	Detail:	RIIO-ED2 Total	Annualised RIIO-ED2	Rationale
Y	Asset replacement	45.1	9.0	See earlier in Annex and specific detail of each element included within Annex 8.1 of our Dec 21 business plan.
	Faults	13.1	2.6	
	Inspections	17.0	3.4	
	R&M	4.0	0.8	
	HVP	31.9	6.4	
	Cable storage	1.4	0.3	
	Subsense	1.4	0.3	
Submarine Cables Total		114.0	22.8	

The annualised cost of £44.6m has three components:

- £22.8m for replacing subsea cables,
- £11.3m for serving the islands (including the costs of maintaining a dedicated subsea cable team),
- £10.5m to mitigate the impacts arising from the sparsity of our region.

In this section, we concentrate on the costs associated with serving the islands and their sparsity. Our response to Ofgem's proposed handling of our subsea cable investment is addressed elsewhere.

Ofgem has rejected our proposals to undertake a separate assessment of our company-specific claims for islands (excluding subsea) equal to the annual value of £2.3m, and all of our costs claimed for

sparsity. Ofgem's reasoning was that they considered that we had not demonstrated that there was a "material difference in benchmarking efficiency performance between SSE's two networks."

Ofgem's assessment is mistaken and inconsistent with previous price control determinations, notably RIIO-ED1. We set out below the key reasons why operating the network in the North of Scotland is materially different and therefore justifies the company-specific factor claims. These draw upon and summarise the detailed justification and analysis provided in Annex 15.7 to our final business plan (Company-specific and regional factors for RIIO-ED2). Since our plan was originally submitted, we have revised the value of all of our proposed company-specific factors, and these are now £44.6m on an annualised basis (of which £11.3m for Islands and £10.5m is for sparsity). This change reflects Ofgem's request to move North of Scotland resilience to Worst- served Customers. We have also identified that our original submission should have contained both OpEx and CapEx costs associated with remote location generation.

The reason we incur additional costs is to ensure that our consumers in the North of Scotland receive the same 24/7 service as consumers elsewhere. To do this, we must have access to staff and resources to prevent network issues arising and be able to respond and restore service as promptly as possible when an unplanned interruption occurs. Achieving the same level of service to communities on islands or living in sparsely populated and mountainous areas exposes us to costs that other DNOs do not face.

We find it surprising that Ofgem has experienced difficulty in recognising the specific factors that drive additional costs in the North of Scotland. In their Final Determination for RIIO-ED1, Ofgem concluded that we had "provided evidence of additional costs associated with SHEPD working in the Highlands and Islands of Scotland. We considered that the submission was generally sound....." and on the basis we received an allowance for company-specific factors. The geography and sparsity of our North of Scotland region has not changed over the course of RIIO-ED1.

To assist Ofgem, we set out below some of the main characteristics of our region that distinguishes it from others, and the impact this has on certain cost categories.

A summary of company-specific factors in the North of Scotland

Table 7 below illustrates some of the fundamental differences between areas in the North of Scotland and those in the SEPD region (which might be used as a proxy for a "typical" DNO). For reference, compared to other parts of our Scottish network, the area which encompasses some of the central belt and Tayside is relatively "urbanised" as it contains Perth, Dundee, Dunblane and Arbroath. However, as the data shows below, SHEPD still a far sparser region than SEPD.

Table 7: SHEPD sparsity data relative to typical UK DNO

	Customers	Customers: Staff ratio	Customer Density (Cust / KM2)	Line Length: Staff Ratio	km Line Length / Depot Area	length of line (km) / km2 per staff member	area (km2)/no properties	customers per property
Western Isles	18,376.00	740.97	6.20	78.48	0.66	0.0265	2,963.00	18,376.00
Orkney	13,920.00	921.85	14.06	116.36	1.77	0.1175	990.00	13,920.00
Shetland	14,296.00	972.52	10.10	105.44	1.10	0.0745	1,415.00	14,296.00
Argyll	65,428.00	893.45	4.10	108.39	0.50	0.0068	1,594.30	6,542.80
Highland	129,138.00	1,042.28	7.29	75.79	0.53	0.0043	2,214.38	16,142.25
South Cal	245,649.00	2,258.44	23.75	108.77	1.14	0.0105	2,585.50	61,412.25
North Cal	301,454.00	2,336.85	38.54	116.11	1.91	0.0148	1,117.43	43,064.86
Total	788,261.00	1,610.34	13.78	100.90	0.86	0.0018	1,787.19	24,633.16
SEPD	3,092,275.00	2,421.89	179.97	61.09	4.54	0.0036	859.10	154,613.75

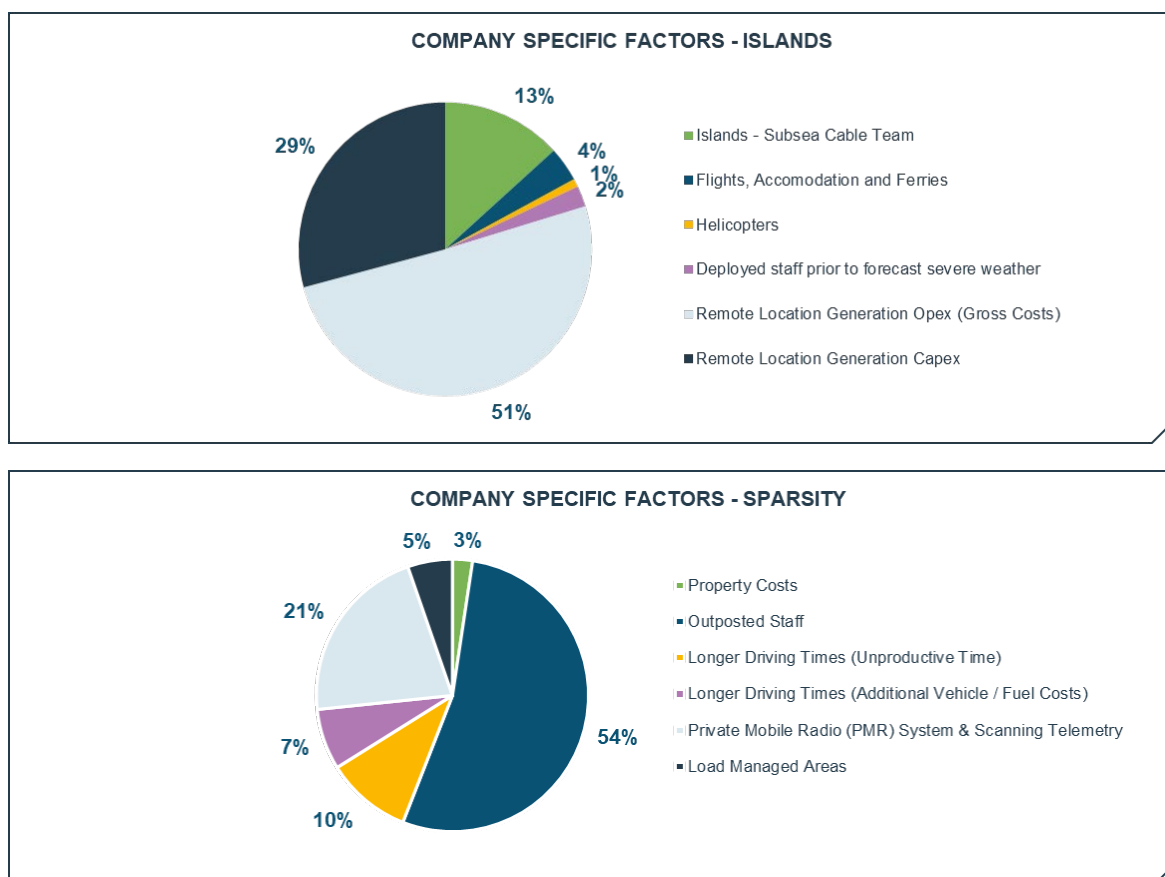
Source: SSSEN

There are some key points to draw from this table:

- The Highlands and Islands have far fewer customers per staff member than other regions
- In the SEPD region there are more customers per square mile and per each staff member. Each depot in SEPD's region serves a relatively small area, but on average covers a much longer line length and a far greater number of customers per property,
- This is as you would expect, however, even when comparing different parts of our Scottish region, there are some stark differences. In the Highlands and Islands, there is very low ratio of customers to staff. While each of our properties in these regions covers an enormous area, they each serve a relatively small number of customers. Each staff member however is, on average, expected to cover a much longer length of line.

These factors inevitably result in additional costs. The charts below provide a breakdown of the cost categories where we propose a company-specific factor should be applied (costs have been annualised).

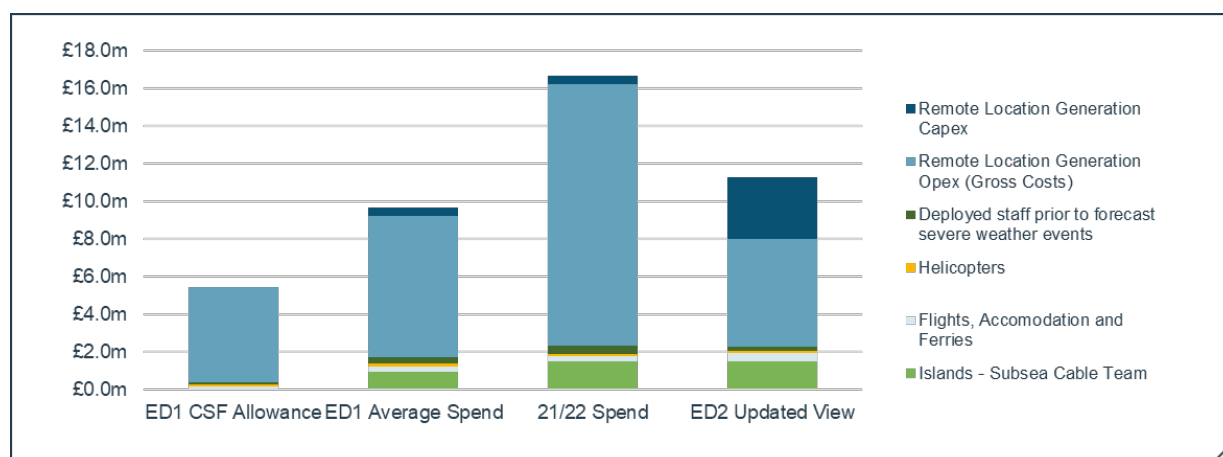
Figure 9: Annualised islands and sparsity company-specific factors



Source: SSEN

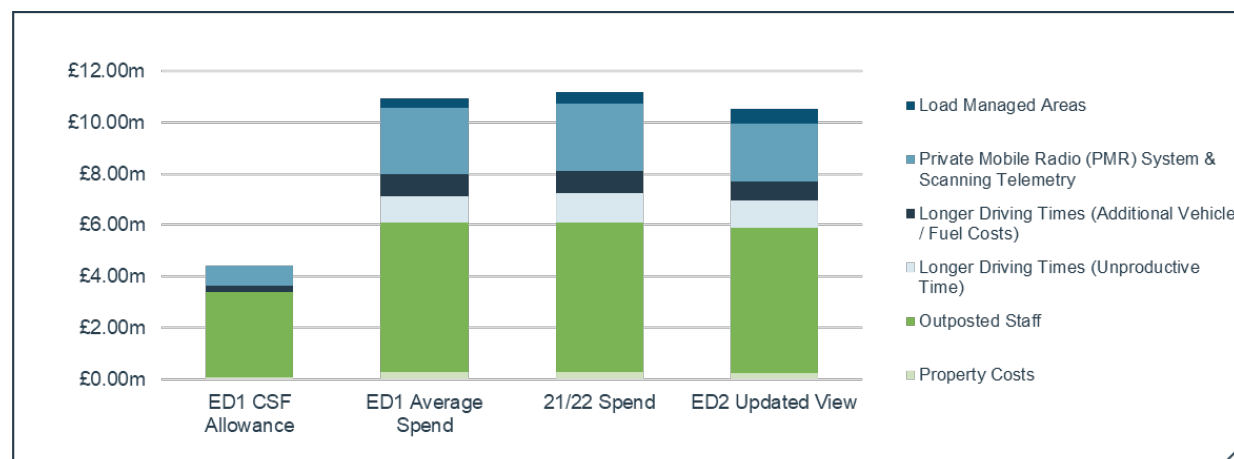
The charts below show how our proposals for company-specific factors compare against historical costs. As is evident, the allowances we were provided by Ofgem in RIIO-ED1 underestimated the additional costs we have been exposed to. Our proposals for RIIO-ED2 broadly track against our average for the period and are lower than the costs we have incurred in the most recent year. We have provided a separate explanation where we are proposing an increase in specific cost items, such as remote location generation capex.

Figure 10: Annualised island costs: ED1 vs ED2



Source: SSEN

Figure 11: Annualised sparsity costs: ED1 vs ED2



Source: SSEN

To ensure Ofgem understands how these cost items support equivalence in service quality, we summarise below some of the main reasons that drive these costs. For full details of our company-specific factor claims, please refer to Annex 15.7 of our final business plan and Appendix F – Business Plan Data Tables of this Annex 10.

Property

The table above highlights that our properties in the North of Scotland serve far few customers than those in the South. This is unavoidable given the vast and remote area of the North of Scotland, but it brings with it higher property costs. To maintain a satisfactory response time in the event of an unplanned interruption, we base members of staff and stores in strategic locations to allow us to respond quickly. These locations are also taken advantage of for planned activity and can save driving time to planned works by reducing the amount of travel time to collect materials from central stores.

Outposted staff

To provide a 24/7 service to our customers in the North of Scotland, we need a baseline resource level to maintain a standby rota. We also need to consider the management of fatigue within our workforce and a 1-in-6 rota frequency is deemed the minimum acceptable on safety grounds. Remote areas require a minimum of three rotas – one Senior Authorised Person (SAP) and two craft roles (two people

are required for working-at-height legislation and also for live working). This means that a minimum of 18 personnel is required to maintain a 24/7 service to our consumers, with some locations also requiring an island manager.

While this is the correct resourcing for these regions, this results in far fewer customers per staff member, and the cost per customer of providing this level and seniority of resource is much higher than other DNOs, who can spread access to resource across a much greater population.

We seek to drive efficiencies through having multi-skilled staff on the islands. Although we may require a higher baseline to serve our customers, we have minimised the requirement by having our craft staff multi-disciplined and our SAPs authorised for all of the required tasks.

Longer driving times

As shown in the table above, given the much greater area and length of line that each staff member is expected to cover, inevitably we face much longer driving times.

Using the relationship between population density and driving times gives an average driving time of 78 minutes per job in an averagely sparse network, defined as a network with population density equal to the population density of Great Britain. In contrast, in our North of Scotland area on average our staff spend 102 minutes of driving per job; this is 30% longer than an averagely sparse network.

Figure 12: Average driving times plotted against population density for SHEPD and SEPD, and the seven regions within SSEN's network



Source: Oxera Report – Annex 15.7 Company Specific Factors

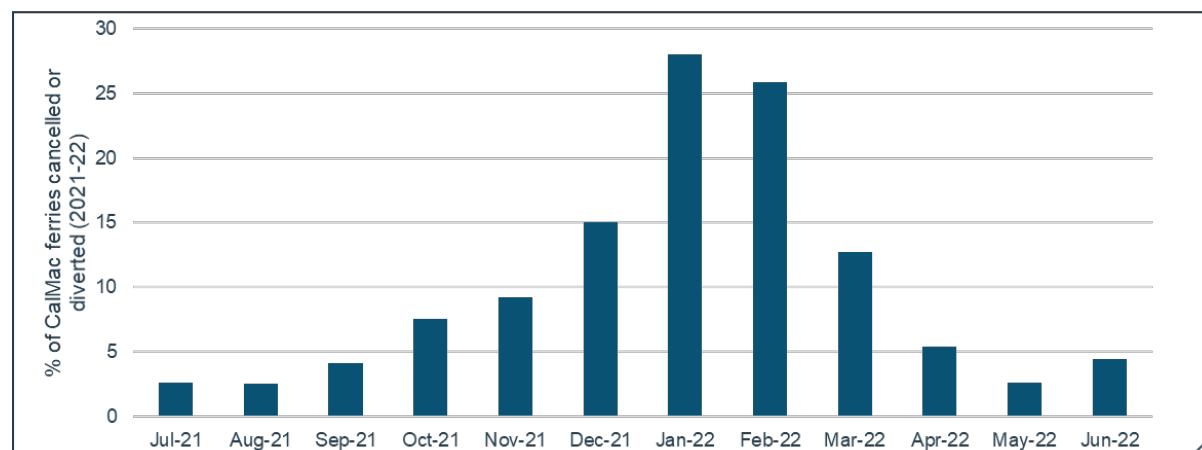
Transport and accommodation

Despite having more properties and outposted staff per customer in the remote areas of our Scottish network, we still must dispatch staff from the mainland and/or between islands to maintain service levels.

Some of our communities and generation sites are not easily accessible or only accessible by air or ferry, for example Stornoway (Battery Point), Lewis and Harris, Loch Carnan, The Uists and Kirkwall and the Orkney Isles. Further, the reliability of transport options such as ferries has reduced significantly in recent years and these are also more susceptible to cancellation. This is due to the severe weather

the region can experience and other well publicised operational challenges local island ferries have experience, this is summarised below.

Figure 13: Scottish CalMac ferry cancellation data



Source: CalMac Ferries audited performance figures ([Route Performance](#) | [CalMac Ferries](#) | [CalMac Ferries](#)).

Where possible, we will mitigate the risk of cancellation or additional travelling time by deploying staff earlier when we anticipate network issues may arise. This maintains a prompt service restoration to our customers but comes with a cost of additional staff downtime and accommodation.

Travel times however tend to be long across the large landmass we cover. Figure 14 highlights some of the most frequent journeys made by our teams and Table 8 shows average travel times by car and ferry, if applicable.

Figure 14: Typical SHEPD journeys from key depots

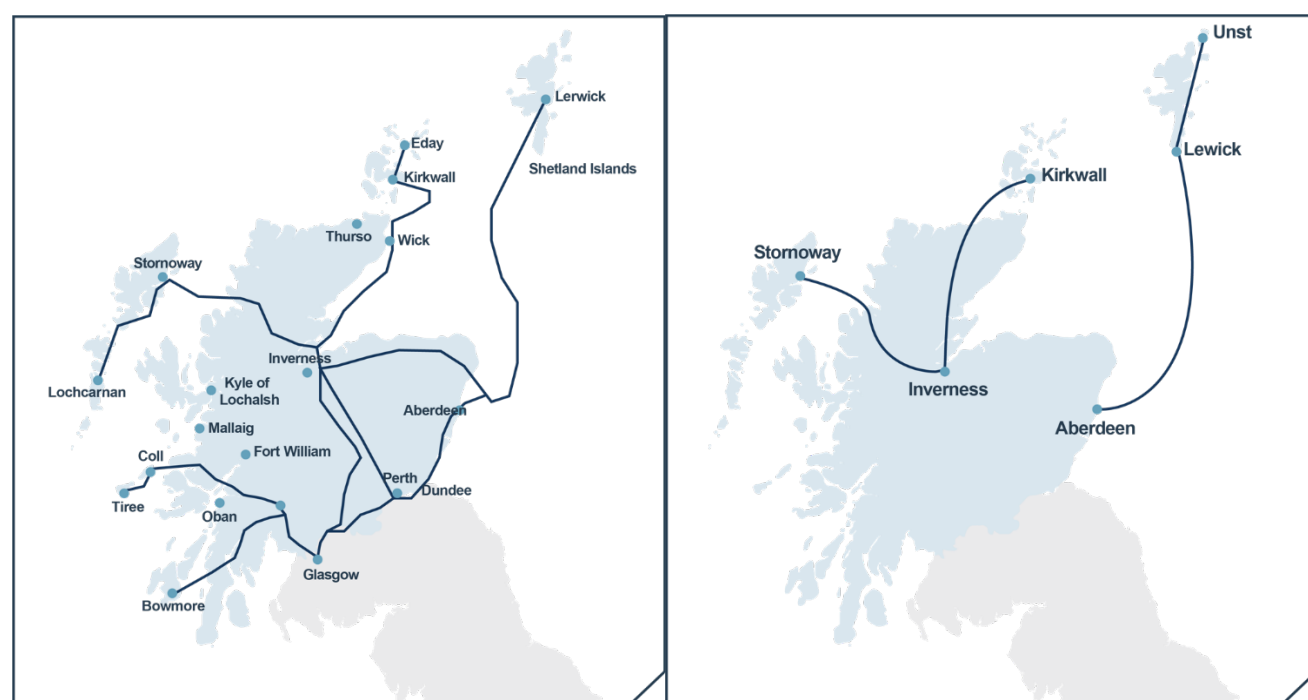


Table 8: Typical SHEPD journey times from key depots

Start	End	Estimated travel time by car (and ferry)
Oban	Tiree	5h
Perth	Oban	2h50
Perth	Inverness	2h15
Perth	Aberdeen	1h30
Glasgow	Bowmore	5h20
Glasgow	Oban	2h30
Kirkwall	Eday	1h45
Inverness	Kirkwall	5h15
Inverness	Stornoway	4h30
Inverness	Loch Carnan	5h50
Lerwick	Unst (Shetland)	2h20
Stornoway	Loch Carnan	4h15
Aberdeen	Lerwick (Shetland)	12h25

Flaws in Ofgem's assessment

The existence of the highlighted company-specific factors is unarguable. It is extremely disappointing therefore that Ofgem appears not to have taken this into consideration. Instead, Ofgem has simply compared costs in the North of Scotland with those in our SEPD region to conclude there is no material difference and therefore there can be no company-specific factors in play.

This is both illogical and inappropriate. When choosing to compare our two licence areas, Ofgem should first have considered the differences in their relative efficiency. SHEPD is one of the most efficient networks across all DNOs - arguably the most efficient. In our business plan we presented analysis that highlighted that once certain anomalies in Ofgem's benchmarking (including removing the costs associated with subsea cables) had been addressed, SHEPD is ranked first of the 14 DNOs in RIIO-ED1, with an UQ gap of -1.8%. In contrast, SEPD is ranked 6th with a UQ gap of 5.2% as shown in the table below.

Figure 15: Relative efficiency position

		TOTEX MODEL	DISAGGREGATED MODEL	RESULTS
EFFICIENCY SCORE	SHEPD	86.2	91.8	88.6
	SEPD	93.2	98.4	95.4
UPPER QUANTILE (UQ)		92.4	93.5	93.5
GAP TO UQ	SHEPD	-6.7	-1.8	-5.2
	SEPD	0.9	5.2	2.0

Source: SSEN

By not identifying any material differences between the two regions, Ofgem's benchmarking has incorrectly treated those costs that are uniquely associated with serving the North of Scotland as being inefficient.

It is irrational to consider these costs as inefficiencies when they are clearly the unavoidable consequence of providing customers with equivalent levels of service regardless of geography and population density.

By setting our cost allowance using benchmarks that do not exclude these factors, Ofgem is putting at risk our ability to maintain equality in service provision. This is not a fair outcome for existing and future customers in this region and also hides inefficiencies within other DNOs performance due to the lack of fair comparability.

[Link to sparsity index](#)

We have proposed a pre-modelling adjustment to account for company-specific factors as we believe this to be the most appropriate mechanism for Ofgem to normalise and separately assess our unique factors.

Ofgem could also utilise an in-model adjustment to account for company specific factors through using a sparsity index, similar to the approach carried out in RIIO-GD2.

Oxera has modelled what the outcome would be within the three separate totex models if a sparsity index was applied in a similar way to the GD1 and GD2 approach, in order to determine appropriateness of our company-specific factor claim.

For each model the sparsity index follows operational insight by having a positive coefficient and whilst this makes a negligible impact in model 1, it does cause a significant improvement to model it within models 2 and 3. More information can be found in the supporting Oxera technical paper attached.

The key output from the in-model adjustment process is that the average sparsity impact across the models, when excluding for remote island generation, is £94.5m vs the £64.0m claim which is calculated through our bottom-up assessed process. This would support that the bottom-up company-specific factors put forward are efficient and should be accepted in full.

[Wage differentials](#)

We provide more details of the importance of recognising wage differentials for our North of Scotland region in the referenced Oxera paper (Cost Assessment Annex F – Regional Wages). In this paper we provide evidence on wage data across regions in GB demonstrating that wages in Scotland are persistently higher than in other regions.

In addition, and in the same Oxera paper (Annex Cost Assessment F), we have provided new evidence to show that regional labour mobility is actually very limited—as generally agreed among economists.

As Professor Ken Mayhew states in his expert report,²³

“In my expert opinion, I consider that Ofgem’s argument is flawed and there is a significant amount of evidence to demonstrate this.”

Widespread shortages of labour across the regions of the UK are likely to have reduced inter-regional mobility in the foreseeable future. If there are plenty of jobs available locally, people have no incentive to relocate for work. As Prof. Ken Mayhew states,²⁴

‘Recent labour market developments are highly likely to have reduced internal migration still further’.

Overall, we suggest that there should be a Scotland-specific regional wage adjustment, or alternatively, a wage adjustment for every region.

The need for Ofgem to revise its Draft Determination

A failure by Ofgem to recognise the unique demands that we face in the North of Scotland will result in existing and future customers in the region being far more exposed to a supply risk than consumers across the rest of the GB network, contrary to Ofgem's statutory duties. We set out below the issues raised by the position taken in the DD.

A summary of our stakeholder-led outputs, and the potential impact on these outputs as a result of Ofgem's DDs is shown below:

Table 9: Draft Determination impact to SHEPD outputs

Strategic Outcome	Output area	Final Business Plan stakeholder-led outputs	Reforecast outputs based on Ofgem's Draft Determination
A safe, responsive and resilient network	Scottish islands	Replacement or augmentation of 15 subsea cables with the greatest needs case	Ofgem's Draft Determination would reduce our Business Plan to only replace or augment 7 subsea cables , this will reduce our planned network resilience improvements by £30m, impacting customers in Orkney, Uist and Inner Hebrides' islands . This will also inhibit the connection of renewable generation on these islands.
A safe, responsive and resilient network	Scottish islands	Three new cables between Skye and Uist, and Pentland Firth West to Orkney	Ofgem's Draft Determination would remove these cables from our business plan , which means these communities will continue to rely on back-up diesel generation .
A safe, responsive and resilient network	Scottish islands	Maintaining and operating standby generation for island communities at our seven island power stations	Ofgem's Draft Determination would reduce our funding to maintain and operate standby generation for island communities , which means we cannot reduce the carbon impact of our back up diesel generation.

Failing to meet demand

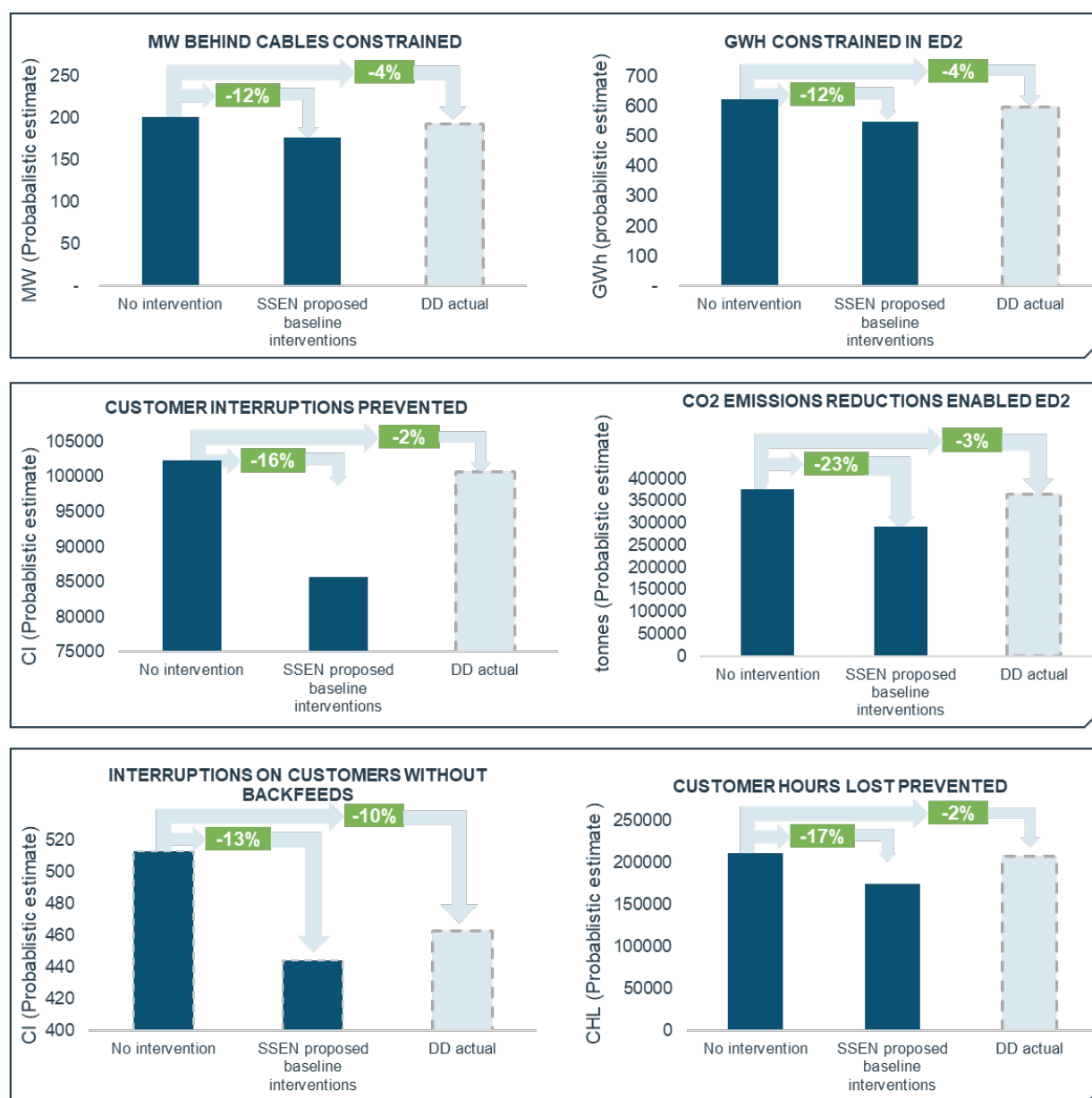
In designing our business plan, our stakeholders explicitly called for greater capacity as the level of renewable generation increases and the need to meet net zero. As discussed earlier, the DFES analysis for the North of Scotland shows a dramatic shift in the use of EV charging and heat pumps. Other potential demand drivers could include the region receiving funding from the £100m Island Growth Deal boosting demand for housing and commercial sites. Contrary to Ofgem's statutory duty to protect the interests of existing and future customers in the reduction of electricity supply emissions of targeted greenhouse gases, the DD would prevent SHEPD from implementing the required investment to meet this demand.

Failing to address network vulnerabilities and not funding improvements

If implemented, Ofgem's DD will create a significant negative impact on consumer and customer experience in terms of lower levels of reliability, contrary to Ofgem's statutory duty to protect the interests of existing and future consumers in their interests in the security of supply of electricity to them. Not having the investment or mechanisms to replace failing subsea cables proactively at the optimal time could result in deterioration in network quality and reliability. Figure 16 below provides a

comparison across six key customer outcomes under Ofgem's DD and our original business plan – highlighting how consumers and customers lose out under the DD. The analysis is constructed from probabilistic fault rate modelling covering the five years of RIIO-ED2.

Figure 16: Subsea cable opportunity costs



Source: SSEN

Similarly, not being able to invest in remote island generation increases both vulnerabilities to cost fluctuations (that cannot be hedged) and reduces our ability to cut emissions.

It will not just be individual consumers affected. Several large commercial customers will also be negatively impacted by delays to subsea cable replacement. For example, delays to the Loch A'Choire work may impact the subsea cables feeding the Glensanda Quarry (largest granite quarry in Europe) or renewable generators unable to obtain business continuity insurance due to subsea cable outages.

Below we present a further example of some of the wider consequences of not replacing subsea cables in a timely fashion.

Stornoway and the wider island of Lewis and Harris are one of the windiest places in the country, but currently dependent on longstanding diesel generators for local power whenever the subsea cable between the mainland on Skye and the island fails.

As well as the island being reliant on diesel when the cable is out of service, increasing its carbon footprint, the islands' windfarms are unable to generate revenue. This has a knock-on effect on the islands' services that rely on grants from windfarms, such as the local Bethesda Care Home and Hospice which receives a grant of £55,000 each year from one of the community wind farms.

Not upgrading the similar cable to South Uist and relying on a cable that is approximately 30 years old will only continue to exacerbate these problems across the islands.

Source: <https://www.stornowaygazette.co.uk/business/community-council-plea-minister-3031933>

Failing to meet stakeholder expectations

As part of our RIIO-ED2 planning, we consulted widely with stakeholders to take onboard their views and needs. Contrary to Ofgem's statutory duties, the DD fails to properly account for stakeholder views and the evidence provided.

One stakeholder during our Orkney consultations expressed particular discontent around subsea cable failures hampering the roll-out of tidal energy projects in the local area:

"The failure of your cables on both sides of Eday is hindering the deployment of marine energy.: You have been holding up a multimillion-pound tidal scheme for around 6 months and are possibly impacting on another one. Given the weather windows, this could delay activities by a year."

Of course, the investments do not just cover subsea cables. Building on the idea of restoring Orkney residents' faith in the strength of the grid and encouraging communities to move forward with their innovative projects that would help make this remote local network more resilient and allow green energy hubs to be created, stakeholders made comments that the entire grid needed to be upgraded so that Orkney residents could enjoy the benefits of their schemes.

"We're concerned that you could be spending all this money on subsea cables, but if you don't upgrade the whole grid, we won't see a benefit. What's the point of communities investing in turbines if they can't make any money from it? If these new generators come on, where are they going to generate from? We need more capacity and fewer constraints, especially when you advertise for more people to start generating."

Stakeholders have also further highlighted the importance of reliability to attract investment and generate new jobs in new industries such as data storage centres. Currently, subsea cable failures are not covered by our customers' business continuity insurance and act as a deterrent for more investment in the islands. Our stakeholder consultation for Orkney noted:

"You should be proactive in making Orkney's generators feel supported practically and financially should there be any cable failures, particularly with insurance cover for such incidences being phased out and even withdrawn for projects in Orkney."

Generators face long-term implications because of grid failure, which can often mean significant financial losses, which they cannot gain insurance cover for. Only a handful of insurers now offer adequate insurance for renewable energy projects, and often only for those of large scale.

One customer has had a quote for its insurance renewal that is 158% of the cost of the previous year, despite no material changes. Critically, all loss of revenue claims relating to subsea cable failures are now excluded from the cover.

The impact of this in the future is that if a single 33kV cable fails, the generators will have no insurance cover. If the outage period is significant, which is often the case, they face insolvency.

Ofgem has a statutory duty to protect the interests of existing and future customers in (a) the reduction of electricity-supply emissions of targeted greenhouse gases; (b) the security of the supply of electricity to them; and (c) Ofgem's fulfilment of the designated regulatory objectives. As detailed below, the DD fails to fulfil these duties for generation customers in this region.

Operational implications if Draft Determination is adopted

If Ofgem continues to not support our balanced funding approach proposal which utilises baseline and Uncertainty Mechanisms, then we would expect our allowances for faults costs (CV26) to be increased post-DD by between £109m and £199m. This increase would be necessary to account for the additional risk we would be taking through our baseline plan, which was not in our original business plan submission because it was based on the assumption of using an Uncertainty Mechanism to shift additional costs to cover cable failure risk to be event-driven rather than ex-ante.

The range covers the additional risk we would be required to manage for replacing subsea cables and the associated fuel costs of running remote island generation sites. It is based on a historic average fault rate of 3.2 per annum for subsea cables; our submitted replacement unit rates for cables between 3-20km long; and an average cable length of 3km for all subsea cables not included in our baseline plan which will be Health Index 5 by the end of RIIO-ED2.

For additional fuel costs, we have based this on a worst-case scenario of data from RIIO-ED1. We used the volume of fuel used at Battery Point power station to cover the recent Skye-Harris fault as a proxy and assume this is repeated every five years. The variability in our figures is driven by fluctuations seen in fuel prices over the last couple of years.

This would be a necessary risk transfer in the event that Ofgem continues to reject the "Fix-on-Fail" Uncertainty Mechanism. If Ofgem adopts the position set out in the DD, we would be forced to reconsider our approach to proactive cable investment in RIIO-ED2 and potentially look to increase allowances between £109m and £199m to cover. This would not be in the interests of current or future consumer in the supply of electricity to them and underlines the need for a "Fix-on-Fail" Uncertainty Mechanism. Without such a 'Fix-on-Fail' Uncertainty Mechanism, or additional funding, we would be forced to evaluate the delivery of planned baseline work because maintaining security of supply for our customers will have to be our abiding priority.

Appendix A – Subsea cables supplementary information

The purpose of this appendix is to provide supplementary information to Ofgem on the following:

- North of Scotland Whole System assessment and Net Zero Island Project.
- Overview of subsea cable investment optioneering strategy.
- Specifics on Horizontal Direction Drilling for subsea cable asset replacement.
- Supplementary justification to support SSEN's subsea cable-specific EJPs.

The above information is considered essential in Ofgem's assessment of our business plan prior to final determinations. The information specifically addresses feedback from Ofgem raised during bilateral meetings, EJP feedback, supplementary questions and a letter issued from the engineering hub.

North of Scotland Whole System assessment and Net Zero Island innovation project

We recognise the need of a strategic approach to manage critical North of Scotland assets to ensure an effective transition to net zero for island communities. That is why we have put forward the Network Innovation Competition Submission Net Zero Island (NZI) Project to Ofgem in August 2022 (decision expected from Ofgem in Oct/Nov 2022). The project seeks to identify and demonstrate sustainable and commercially viable whole system options, to eliminate the use of carbon-intensive diesel generation for maintaining supplies to our remote island communities in the North of Scotland. This is a pressing need, essential to allow us to meet our Science Based Targets and be capable of accelerating local decarbonisation ambitions.

In the event of a subsea cable fault, there is no readily available low carbon solution to replace the use of diesel generators for maintaining supplies over long durations,. The NZI project will take a structured approach to identifying an alternative, whilst engaging and supporting our wider Scottish island strategy, Scottish Government and local island strategies. They will include, among other activities, working with other innovation programmes to identify emerging long duration energy storage technologies, as well as mobilising demand-side options to support resilience, and identifying the likely viable options from a technical, economic and sustainability perspective, ensure alignment with HOWS UM.

Overview of subsea cable investment optioneering strategy

As part of all subsea cable investments, once a cable has been identified and confirmed as requiring intervention, a detailed optioneering phase is conducted. In general, this optioneering considers a number of standard subsea cable options and some site-specific options if applicable, as below:

- Do nothing
- Fix on fail
- Replace on fail
- Like-for-like replacement
- Upgraded cable sizing
- Augmentation

Site specific optioneering

- Horizontal Directional Drill (HDD)
- Land-based solution

In terms of the site-specific options, these are considered in detail where site specific conditions allow. Although the options can be considered under all cable scenarios, they would very quickly be rejected due to site location and conditions not being suitable for their application. For example, a land-based solution can only be considered if the topography and local infrastructure of the location allows (for example a nearby bridge or causeway).

In general, subsea cables have been laid in their existing location due to the unsuitability of the local terrain for typical land cables or overhead lines. Or that distances around the watercourse would be too long as an effective solution or network operation becomes an issue due to voltage drop etc. Additional challenges with land / onshore routes relate to ground conditions - peat, excessive rock, historical artifacts and environmentally restricted areas all add additional times, cost, resource and risk to the delivery of projects.

Specifics on Horizontal Directional Drilling (HDD) for subsea cable asset replacement

An HDD solution is only considered viable and included in the options assessment if a number of constraints and/or conditions are present e.g. length of crossing, suitable lay down areas, duct stringing, site access, cable pulling tensions and ground type etc. HDD is not always a viable solution for any watercourse crossing that falls within certain technical parameters, such as drilling length, as ground conditions, site access for equipment or cable pulling tensions could all prevent a successful solution. A suitable and plentiful water supply is also required during drilling for the mixing of drill fluids.

Based on previous and ongoing HDD feasibility studies, there is a limited drilling length through which an electricity power cable can be pulled without exceeding the pulling tensions of 33kV or 11kV cable. Although HDD can be complete over several kilometres - usually through drilling from both ends and meeting in the middle - power cables have a maximum pulling tension which is generally exceeded where a drill length of circa 1.5km is exceeded for 33kV cable. This pulling tension calculation is confirmed as part of HDD desktop and feasibility studies in each individual case and it may be possible for slightly longer lengths of pull or subsequently not possible for shorter lengths, dependent on the specific proposed/indicative drill design route.

Therefore, as a general rule, we will reject/discount the HDD option for subsea cable crossing lengths in excess of 2km. RIIO-ED1 experience has concluded that a 1.5km drill is probably on the limit of being likely feasible, whilst a 1km drill would be a more reasonable expectation of having a successful drill and cable pull-in, given the geography and geological make up of our network area.

The longest successful onshore HDD in the world (in the public domain) was recorded at a length of circa 4.5km. This was for a water pipe in 2017 in the Netherlands. However, based on initial research, the longest successful power cable HDD installation was in 2012 for a 121kV transmission cable - this route length was circa 1.9km. The drills required to drill this length from one end have significant cost and transportation challenges, as well as increased lay down areas and ancillary equipment. As detailed, a drill could be achieved by drilling from either end but will result in either double the drill costs for two smaller machines, or increased costs associated with the relocation and mobilization of the smaller drill to the other side of the drill, assuming suitable site laydown and access is available. The 2012 project referred to earlier was delivered in Wolf Bay, Alabama by Southeast Directional Drilling on behalf of PowerSouth Energy Cooperative. This drill was approximately 30m below the seabed.

In the majority of cases in SHEPD, our existing submarine cable assets and the associated onshore connections, are in extremely challenging locations. Generally, the coastline is very rocky, rugged and steep banked. This can stretch for a number of kilometres along the coastline meaning that moving landing locations generally results in similar installation conditions. This makes finding suitable locations for the HDD laydown compound difficult. The minimum compound size generally required is a 50m x 50m, it is required to be flat and/or able to be levelled, have access for required machinery and plant, have a local useable water source or have the ability to bring water to site.

These conditions prove difficult to find in most of our locations on one side, and even rarer to find on both shore end landings if requiring/proposing to drill from both sides of the crossing. In addition, to the drill-side compound, there must be a suitable pop-out location on the alternate shore side. This pop-out location must also have a suitable lay back area for ducting to be strung out in advance of duct pull-in. The logistical challenges of getting heavy drilling equipment to these sites has proven prohibitive in the past due to road loading restrictions, ferry sizes, vessel chartering, island access and general site access.

Another consideration which is given during our desktop studies is the depth of the water crossing as the drill requires to travel under the water course/river/loch before popping out to give an end-to-end HDD solution. Therefore, the deeper and steeper the marine crossing, the further this can affect setback distances for drilling. Again, this limits drilling locations and compound set-ups. In the majority of the areas where we have shorter crossings, which may be possible to drill, the seabed depths are typically in the region of 10-50m.

Furthermore, standard land cable, which is generally used within the HDD duct, comes on drums/reels with a standard length of 500m. Anything beyond this requires a special order. i.e., on the recent Corran Narrows HDD project non-standard drums of 800m were required to allow a continuous cable pull through the ducting.

Initial desktop progress has been made on the proposed HDD replacement for the existing Jura-Islay subsea cable replacement. The drill length is anticipated to be approximately 1.4km in 3D length (remembering that the line across a map does not account for the physical drilling length when considering drilling angles, set back length and depth of crossing). Through engagement with cable suppliers, this is on the boundary of the longest continuous length of cable which could be supplied on a single drum, indicated to be around 1.5km. This is for 33kV singles, any 3-core cable would be of a significantly reduced length.

These cable drums pose their own issue with transportation given their size and therefore it may not be possible to get this cable to site, even if considering cable barges and suitable landing locations. The question is then posed around jointing cable lengths together to achieve longer pull ins, however any cable joint would reduce the pulling tension which could be applied to the cable as the join is likely to be compromised when subject to these forces. Additionally, this would introduce a weak spot in the cable HDD for the future and this joint would not be accessible to repair, should it fail. This would lead to a full cable replacement being required. For these reasons, jointed cable pull-ins are not considered when assessing HDD feasibility.

Subsea cable can be considered for the HDD pull through, but in general is not road-transportable given the minimum bending radius of the cables and with it being 3-core wrapped armoured cable, 1.5km of cable would not sit on a road transportable reel. Subsea cables have higher pulling tensions but have much greater cable weight and also cause additional technical issues with circulating currents and temperature rise within ducting, especially when considering longer length installations. Therefore, subsea cable is not generally considered as feasible for installation in end-to-end HDDs within SHEPD.

Providing all of the site-specific requirements are in place for the set up and transport of the HDD equipment, the drill will then be subject to a full on and offshore feasibility, where the ground conditions, type and make up will be assessed. Subject to these outcomes the drilling of the route may not be feasible. This could be due to the rock being too soft or made up of sandy matter, which could cause bore hole collapse. There may be portions

of glacial tilt which effects the ability to steer the drill and to make progress. This was an issue which was present on the recent Corran Narrows project which, even though it was deemed feasible from desktop and full feasibility studies, proved extremely challenging to drill through with several drill attempts required at differing angles, before an adjustment to the pop-out location allowed a successful drill. While this avoided the majority of the glacial material on this project, it won't always be possible on future projects which means an unsuccessful drill could still result following a 'go' decision from a feasibility report.

As discussed, there are a number of factors which must be present and suitable for the proposal of an initial HDD solution. There are very few scenarios where all of the ideal conditions are present at the same time. Sometimes non-ideal conditions can be tolerated, but this does increase project risk and most likely cost.

Following acceptance that a site is suitable, a full HDD feasibility must be conducted, usually at a cost of around £500k. Should this then be deemed feasible, works can progress on the design and ultimate construction of the HDD route. During the construction phase, drilling is unpredictable, even with the data and outputs from intrusive and non-intrusive surveys.

Under both recent HDD projects undertaken by us at Corran Narrows and Carradale, there has been a loss of drill fluid returns, i.e. the lubricant and return material go into a cavern or rock whilst drilling and this can lead to either the drill being unable to progress or significant time and significant expenditure is required to attempt to fill the cavern/crevasse or we have to adapt drilling fluids - again this can be unsuccessful, resulting in a failed drill attempt.

Drilling equipment can get stuck or broken in the drill hole resulting in a blockage or stoppage, with the potential to stop drilling or requiring a new hole to be drilled. Whilst reaming there is a chance the borehole can collapse, again leading to blockages or stoppages. When a hole is complete there can be issues with duct pull-ins, either ducting being caught or stopped in the hole or pipe welding can fail leading to partially ducted routes. This is all before a cable is attempted to be pulled, with similar risks to ducting. The cable is monitored to ensure it remains within the pulling tension of the cable parameters, as although desktop calculations may deem pulls to be OK, the physical real-world pull can perform differently. The cable is then subject to electrical testing before final energisation.

At any point through the execution and construction phase of the project the HDD could be deemed a failure and/or not possible and have to be abandoned. All of the construction issues highlighted are highly likely to lead to significant project cost increases as well as significant project delays.

All of the issues highlighted are real issues which SHEPD has encountered whilst performing HDD projects over much shorter lengths (400-900m), compared with those considered as possible within initial optioneering (2000m) during RIIO-ED1. As the length of drill increases, the risks of encountering the execution issues also increase.

It is therefore clear, that HDD is not a simple solution to consider solely based on a short crossing on a map, but in fact requires a large number of ideal factors to be in place before the option can progress to feasibility study. This is why HDD is ruled out as a plausible option for replacement of subsea cables in many instances prior to a detailed option assessment, and therefore not included on some EJPs submitted to Ofgem for consideration. The potential risks and viability of a successful drill also have to be weighed up against the lower risk installation of a subsea cable, when looking at options for cable replacement.

The costs of HDD are not certain and can grow exponentially during the construction phase, or indeed be all a "regretted spend" if a drill is not successful. This risk profile must be carefully considered by us to ensure safe and efficient solutions are developed to deliver value for consumers.

Supplementary justification to support SSEN's subsea cable-specific EJPs

CV25 – High Value Projects

SSEN EJP: 458/SHEPD/SUBSEA/SKYS_UIST_SOUTH – Skye to South Uist (South Route)

DD Status: 'Unjustified'

Supplementary information to support justification

Although our CBA outputs show that the best value solution is to replace the existing asset with two new cables, we accept that there may be an alternative 'whole system' solution which forms a better long-term outcome. Hence the north route has been included within our submission as part of the HOWS UM and not included in the baseline request. We have taken this approach to ensure that the base risk of the existing subsea cable can be managed effectively to protect customers' security of supply whilst allowing time for further investigation of the best whole life solution for the whole island group, given the number of ongoing developments in the region. This does not commit customers to paying for a second cable at this time as part of our baseline request and makes it subject to further assessment and submission from us as part of the whole system uncertainty mechanism, which in itself will determine new delivery timescale for any proposed solution.

This de-links the proposals for a north and south link and ensures that we can effectively manage the immediate network risk to customers, through baseline allowance, given the age and health index of the existing cable, providing a secure and reliable supply to the islands whilst the second (north cable) is further assessed to provide an even greater security of supply and cater for further demand growth.

The south route EJP should be considered on its own merit to manage the risk of the existing circuit, whether this be a single replacement at this time or indeed an augmented solution. This approach will not affect the future delivery of second cable to North Uist, which was determined in the current CBA to be the best overall NPV to replace the single cable.

The south cable must be justified and accepted irrespective of the investment decision to progress the second cable after the HOWS UM assessment.

It is not an acceptable position for us to not replace the Skye to South Uist cable within RIIO-ED2. This places an unacceptable level of risk on our customers within this island group. The north cable will be further assessed and submitted to OFGEM as part of the HOWS UM and can be independently assessed at the time.

CV7 – Asset replacement projects

SSEN EJP: 403/SHEPD/SUBSEA/MAINLAND_KERRERA2 – Mainland to Kerrera 2

DD Status: 'Unjustified'

Supplementary information to support justification

Of the two mainland to Kerrera cables, it is this cable driving the need for replacement within RIIO-ED2. The cable has been in service for over 15 years and provides one of the connections from mainland Scotland out to the Isle of Kerrera, then ultimately out to Mull, Iona, Coll and Tiree.

The criticality (number of customers impacted) of these subsea feeder cables is driving the proactive replacement. Given the age and short length, the existing cables would not be repaired in the event of a fault. Full replacement would be performed.

Given this cable is forecast to be a HI5 by the end of the price control we would like to proactively replace the existing cable to reduce and minimise risk to all customers supplied via this strategically important cable. We would look to proactively replace the Mainland to Kerrera 1 cable during the same installation campaign to deliver the projects in the most efficient manner: utilise proven installation assets while capitalising on greater economies of scale when negotiating with our supply chain. It would also offer synergies from a technical design, marine survey and marine licence perspective. Although the Mainland - Kerrera 1 cable is not forecast to reach HI5 until the first year of RIIO-ED3, deferring the replacement of Mainland – Kerrera 2 until RIIO-ED3 would put undue risk onto the security of supply for a whole island group with one cable at end of life and the other approaching end of life, giving the real possibility that both cables could fail.

Additionally, by undertaking this proactive replacement within the RIIO-ED2 price control period, this will allow us to better manage current and future replacement requirements and help in avoiding a bow wave of investment in future price controls striking a balance between cost burdens on current and future consumers whilst managing the overall network risk to consumers and customers.

It should be noted that although these cables were originally proposed to be complete alongside installation of the two Loch A'Choire cables, there is no technical or operational requirement to link the delivery in a single campaign. It was a geographical link that offers further efficiencies we are keen to capitalise on. There is no risk to project delivery if the mainland to Kerrera cables are delivered in a standalone campaign.

The CNAIM Asset Health Score Data for the cables is as follows:

	ED1		ED2					ED3
Circuit	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026	Year 2027	Year 2028	Year 2029
Mainland to Kerrera 2	5.5 HI 3	5.95 HI 3	6.43 HI 3	6.96 HI 4	7.53 HI 4	8.14 HI 5	8.81 HI 5	9.53 HI 5
Mainland to Kerrera 1	5.5 HI 3	5.81 HI 3	6.14 HI 3	6.49 HI 3	6.86 HI 4	7.25 HI 4	7.66 HI 4	8.09 HI 5

SSEN EJP: 441/SHEPD/SUBSEA/JURA_ISLAY – Jura to Islay

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 395/SHEPD/SUBSEA/COLL_TIREE – Coll to Tiree

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 331/SHEPD/SUBSEA/HOY_FLOTTA – Hoy to Flotta

DD Status: 'Unjustified'

Supplementary information to support justification

It is acknowledged that the CNAIM Health Index Data for the cable does not show its condition as HI5 within RIIO-ED2. However, the age and criticality of the network being supplied are driving us to ensure security of supply is not impacted. The Flotta Oil Terminal and renewable generation on the island make the cable strategically important.

Our response to Ofgem's SQ in March 2022 (SSEN122) provided further clarity on the importance of an augmented solution, which offered the ability to extract maximum value from the existing asset but adding additional network resilience.

There are other subsea cables planned for proactive replacement in Orkney. Including this cable as part of a bundled solution will deliver the projects in the most efficient manner, utilising proven installation assets while capitalising on greater economies of scale when negotiating with our supply chain. In addition, it would also offer synergies from a technical design, marine survey and marine licence perspective.

SSEN EJP: 335/SHEPD/SUBSEA/LOCH_LONG – Loch Long (Dornie)

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 338/SHEPD/SUBSEA/MULL_IONA – Mull to Iona

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 394/SHEPD/SUBSEA/ORKNEY_SHAPINSAY – Mainland Orkney to Shapinsay

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 405/SHEPD/SUBSEA/LAXAY_KERSHADER2 – Laxay to Kershader 2

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 457/SHEPD/SUBSEA/LOCH_A'CHOIRE_NORTH – Loch A'Choire North

DD Status: 'Unjustified'

Supplementary information to support justification

While we originally proposed to complete the installation of the two Loch A'Choire cables as part of a combined campaign with the two mainland to Kerrera cables, there is no technical or operational requirement to link the

delivery of these cables in a single campaign. It was a geographical link, in the water, that offers further efficiencies we are keen to capitalise on. There is no risk to project delivery if the mainland to Kerrerra cables are delivered in a separate campaign.

Both the Loch A'Choire subsea cables are already classified as HI5 and will continue to deteriorate as we progress through RIIO-ED2. It is imperative that both Loch A'Choire cables are proactively replaced given they are already at end-of-life and over 35 years old, they also supply Glensanda super quarry, the largest granite quarry in Europe producing in excess of 9 million tonnes per year.

We have recently replaced the 33kV subsea cables at Corran Narrows with an HDD solution which has greatly increased the resilience of supply to this section of the network. The replacement of the Loch A'Choire north and south cables will ensure that the whole supply to Glensanda is benefiting from greater resilience and security of supply.

In addition, as mentioned in our EJPs and as demonstrated as part of the OFGEM/SHEPD site visits, the relocation of the cable landing points will allow us to further strengthen the resilience of this network. Several spans of 33kV OHL currently go over mountainous terrain which is inaccessible and poses operational risk to staff. This network was installed using techniques which are no longer applied given the increased requirement for health and safety at work. We are only able to inspect these assets by helicopter and replacement would be impossible in the current location following a failure. The removal of these assets is an additional benefit that will be delivered as part of these cable replacements.

SSEN EJP: 333/SHEPD/SUBSEA/LOCH_ACHOIRE_SOUTH – Loch A'Choire South

DD Status: 'Unjustified'

Supplementary information to support justification

While we originally proposed to complete the installation of the two Loch A'Choire cables as part of a combined campaign with the two Mainland to Kerrerra cables, there is no technical or operational requirement to link the delivery in a single campaign. It was geographical link that offers further efficiencies we are keen to capitalise on. There is no risk to project delivery if the Mainland to Kerrerra cables are delivered in a separate campaign.

Both the Loch A'Choire subsea cables are already classified as HI5 and will continue to deteriorate as we progress through RIIO-ED2. It is imperative that both Loch A'Choire cables are proactively replaced given they are already at end-of-life and over 35 years old, they also supply Glensanda super quarry, the largest granite quarry in Europe producing in excess of 9 million tonnes per year.

We have recently replaced the 33kV subsea cables at Corran Narrows with an HDD solution which has greatly increased the resilience of supply to this section of the network, the replacement of the Loch A'Choire North & South cables will ensure that the whole supply to Glensanda is benefiting from greater resilience and security of supply.

In addition, as mentioned in our EJPs and as demonstrated as part of the OFGEM/SHEPD site visits, the relocation of the cable landing points will allow us to further strengthen the resilience of this network. Several spans of 33kV OHL currently go over mountainous terrain which is inaccessible and poses operational risk to staff. This network was installed using techniques which are no longer applied given the increased requirement for health and safety at work. We are only able to inspect these assets by helicopter and replacement would be impossible in the current location following a failure. The removal of these asset is an additional benefit that will be delivered as part of these cable replacements.

SSEN EJP: 414/SHEPD/SUBSEA/KINTYRE_GIGHA – Kintyre to Gigha

DD Status: 'Justified'

Supplementary Info to Support Justification: Not required

SSEN EJP: 404/SHEPD/SUBSEA/MAINLAND_KERRERA 1 – Mainland to Kerrera 1

DD Status: 'Unjustified'

Supplementary information to support justification

Of the two mainland to Kerrera cables, it is the Mainland to Kerrera 2 cable driving the need for replacement within RIIO-ED2. Notwithstanding, this cable has been in service for almost 30 years and provides one of the connections from mainland Scotland out to the Isle of Kerrera, then ultimately out to Mull, Iona, Coll and Tiree.

The criticality (number of customers impacted) of these subsea feeder cables is driving the proactive replacement. Given the age and short length, the existing cables would not be repaired in the event of a fault. Full replacement would be performed.

We would look to proactively replace the Mainland to Kerrera 2 cable during the same installation campaign to deliver the projects in the most efficient manner: utilise proven installation assets while capitalizing on greater economies of scale when negotiating with our supply chain. It would also offer synergies from a technical design, marine survey and marine licence perspective.

Although the Mainland – Kerrera 1 cable is not forecast to reach HI5 until the first year of RIIO-ED3, deferring the replacement of Mainland – Kerrera 2 until ED3 would put undue risk onto the security of supply for a whole island group with one cable at “end-of-life” and the other approaching end-of-life, giving the real possibility that both cables could fail. Given the efficiencies which can be gained in delivering both projects together it is appropriate to replace this mainland – Kerrera 1 cable proactively just ahead of need to ensure both circuits feeding this island group are secure and reliable.

Additionally, by undertaking this proactive replacement within the RIIO-ED2 price control period, it will allow us to better manage current and future replacement requirements and help in avoiding a bow wave of investment in future price controls, striking a balance between cost burdens on current and future consumers whilst managing the overall network risk to consumers and customers.

It should be noted that although these cables were originally proposed to be complete alongside the installation of the two Loch A'Choire cables, there is no technical or operational requirement to link the delivery in a single campaign, it was simply a geographical link that offers further efficiencies we are keen to capitalise on. There is no risk to project delivery if the Mainland to Kerrera cables are delivered in a standalone campaign.

The CNAIM Asset Health Score Data for the cables is as follows:

	ED1		ED2					ED3
Circuit	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026	Year 2027	Year 2028	Year 2029
Mainland to Kerrera 2	5.5 HI 3	5.95 HI 3	6.43 HI 3	6.96 HI 4	7.53 HI 4	8.14 HI 5	8.81 HI 5	9.53 HI 5
Mainland to Kerrera 1	5.5 HI 3	5.81 HI 3	6.14 HI 3	6.49 HI 3	6.86 HI 4	7.25 HI 4	7.66 HI 4	8.09 HI 5

M13 – Asset Replacement – Hebrides & Orkney Whole System UM

SSEN EJP: 328/SHEPD/SUBSEA/SKYS_UIST_NORTH – Skye to South Uist (North Route)

DD Status: 'Unjustified'

Supplementary information to support justification

This cable will be further justified, if appropriate as part of the HOWS Uncertainty Mechanism proposed by us. This north cable should be treated in isolation when considering the justification and funding for the Skye to South Uist South cable as the existing cable must be replaced as a minimum through the RIIO-ED2 price control to manage network risk to an acceptable level.

SSEN EJP: 329/SHEPD/SUBSEA/PFW – Pentland Firth West

DD Status: 'Justified'

Supplementary information to support justification

This cable will be further justified, if appropriate as part of the HOWS Uncertainty Mechanism proposed by us.

SSEN EJP: 388/SHEPD/SUBSEA/ORKNEY_HOY_SOUTH – Mainland Orkney to Hoy South

DD Status: 'Justified'

Supplementary information to support justification

This cable will be further justified, if appropriate as part of the HOWS Uncertainty Mechanism proposed by us.

SSEN EJP: 390/SHEPD/SUBSEA/ERISKAY_BARRA_2 – Eriskay to Barra 2

DD Status: 'Justified'

Supplementary information to support justification:

This cable will be further justified, if appropriate as part of the HOWS Uncertainty Mechanism proposed by us.

SSEN EJP: 401/SHEPD/SUBSEA/SUIST_ERISKAY – South Uist to Eriskay

DD Status: 'Unjustified'

Supplementary information to support justification

This cable will be further justified, if appropriate as part of the HOWS Uncertainty Mechanism proposed by us.

Appendix B – Remote generation supplementary information

The purpose of this appendix is to provide supplementary information to Ofgem on the following:

- North of Scotland Whole System assessment and Net Zero Island innovation project.
- Supplementary justification to support our remote embedded generation specific EJP.

The above information is considered essential in Ofgem's assessment of our business plan prior to its final determinations. The information specifically addresses feedback from Ofgem raised during bilateral meetings, EJP feedback, supplementary questions and a letter issued from the engineering hub.

[North of Scotland Whole System Assessment and Net Zero Island innovation project](#)

SSEN recognises the need for a strategic approach to manage critical North of Scotland assets to ensure an effective transition to net zero for island communities. That is why SSEN has put forward the Network Innovation Competition Submission Net Zero Island (NZI) Project to Ofgem in August 2022 (decision expected from Ofgem in Oct/Nov 2022). The project seeks to identify and demonstrate sustainable and commercially viable Whole System options to eliminate the use of carbon intensive diesel generation for maintaining supplies to our remote island communities in the North of Scotland. This is a pressing need, essential to allow SSEN to meet its Science Based Targets and be capable of accelerating local decarbonisation ambitions.

In the event of a subsea cable fault, there is no readily available low carbon solution to replace the use of diesel generators for maintaining supplies over long durations. The NZI project will take a structured approach to identifying an alternative, whilst engaging and supporting our wider Scottish island strategy, Scottish Government and local island strategies. They will include, among other activities, working with other innovation programmes to identify emerging long duration energy storage technologies as well as mobilising demand-side options to support resilience, and identifying the likely viable options from a technical, economic and sustainability perspective, ensure alignment with HOWS UM.

[Supplementary justification to support SSEN's remote embedded generation-specific EJP](#) [CV15 – QoS & NoSR](#)

SSEN EJP: 345/SHEPD/REGIONAL/BATTERYPOINT – Island Generation – Battery Point

DD Status: 'Partially Justified'

Supplementary Information to support justification

We do not agree that risk should be preventing justification of the EJP.

The below addresses any changes since final business plan submission and Ofgem's engineering review comment from the DD. In addition to the engineering review comment, Ofgem also provided further clarity of its concerns through the response to the reverse SQ SSEN023. Ofgem challenged the justification of choosing option 3 over option 2, as well as the long-term strategy of diesel generators. The section below also seeks to address these two concerns.

Expected outputs

The output for the preferred option will be delivery of two new 5MW generators at Arnish Power Station on Stornoway. These generators will replace the oldest and least reliable generators at Battery Point Power Station on Stornoway, by removing them from service after the new generators are installed.

The location of generator replacement has changed from Battery Point Power Station to Arnish Power Station on Stornoway for several reasons:

- Battery Point is a congested site; therefore, the station would not be able to remain operational during obsolete generator engine removal and subsequent install of the new generators
- Head clearance and other safety considerations above the operating cranes over the remaining generators would be an issue due to the constrained space at Battery Point
- The proposed new generators require Selective Catalytic Reduction (SCR) systems to be incorporated into the exhaust system. This cannot be accommodated in Battery Point's current site plan given the external space the SCR require
- Considering Battery Point Power Station's proximity to residential housing, the Scottish Environmental Protection Agency (SEPA) has expressed concerns over locating the new generators there due to noise and air pollution.

Considering this, Arnish Power Station has been determined the better site as it has capabilities to remove the old generators and install the new generators without impact to its operation.

Additionally, engines at Arnish Power Station can be remotely operated from our North of Scotland control room providing faster response time and greater security of supply to consumers. Arnish is also further away from residential housing which limits pollution impacts on people.

Optioneering

Ofgem has rightly noted the marginal differences between options 2 and 3 in the CBA. However, this is largely because option 2 simply delays the replacement of the old engines (numbers 5 and 6), into RIIO-ED3.

It is clear that there would be no benefit to consumers in replacing only two KVSS engines at Battery Point given the outlined issues with performance, availability and cost of spares, operational compliance and environmental impact. Generator 1 has already been removed from service due to major failure; given its age and past performance, it was not cost effective to repair. The remaining 3 KVSS engines (numbers 2, 5 and 6) continue

to struggle to meet the needs of our permit limit values. During recent emissions testing at Battery Point Power Station via an independent external contractor, Engine 6 unfortunately failed the NO_x emission limit value, resulting in a minor breach notification to SEPA. This is shown in the table below.

Table 1. Emissions testing results for Engine 6 at Battery Point Power Station

Emissions Summary					
Parameter	Units	Result	Calculated Uncertainty +/-	Emission Limit Value (ELV)	Accreditation
Total Particulate Matter	mg/m ³	86.4	3.37	100	MCERTS
Particulate Emission Rate	g/hr	1671	65.2	-	
Oxides of Nitrogen (as NO ₂)	mg/m ³	1976	74.9	1850	MCERTS
Oxides of Nitrogen (as NO ₂) Emission Rate	g/hr	38153	1446	-	
Carbon Monoxide	mg/m ³	283	4.04	350	MCERTS
Carbon Monoxide Emission Rate	g/hr	5477	78.0	-	
Oxygen	% v/v	11.8	0.05	-	MCERTS
Moisture	%	4.07	0.17	-	MCERTS
Stack Gas Temperature	°C	300	-	-	MCERTS
Stack Gas Velocity	m/s	11.5	0.28	-	
Gas Volumetric Flow Rate (Actual)	m ³ /hr	27622	1421	-	
Gas Volumetric Flow Rate (STP, Wet)	m ³ /hr	13185	678	-	
Gas Volumetric Flow Rate (STP, Dry)	m ³ /hr	12649	651	-	
Gas Volumetric Flow Rate at Reference Conditions	m ³ /hr	19315	993	-	

ND = None Detected,

Results at or below the limit of detection are highlighted by bold italic text.

The above volumetric flow rate is calculated using data from the preliminary survey. Mass emissions for non isokinetic tests are calculated using these values. For all isokinetic testing the mass emission is calculated using test specific flow data and not the above values.

Reference conditions are 273K, 101.3kPa, dry gas 15% Oxygen.



Engine 6 will shortly receive a 12,000-hour overhaul which should improve the NO_x emissions associated with its use; however, the remaining KVSS engines in service are consistently pushing the upper NO_x limit upon testing. Therefore, further breaches could be expected.

Additionally, only replacing two KVSS engines with one new efficient engine as proposed presents risk where the remaining KVSS engines fail or become completely unsupportable. This would directly impact available capacity and, in periods of high demand (during winter or a fault), there would be a multitude of challenges in ensuring security of supply to our island communities.

Therefore, we continue to propose replacing all 4 KVSS engines -numbers 1, 2, 5 and 6 - at Battery Point Power Station with two new engines at Arnish Power Station, Stornoway.

Deliverability and risk

This section discusses our intended approach to delivering the two new 5MW generators at Arnish Power Station on Stornoway. It summarises the lead time to delivery as well as highlighting any risks or constraints, addressing Ofgem's comments surrounding delivery risk.

Lead time to delivery

A feasibility study by an external consultant has been completed to ensure that the existing site at Arnish Power Station can accommodate an additional building to contain the two new engines, their ancillary systems, and the Selective Catalyst Reduction exhaust equipment. Associated costs for the building were also determined during this study.

A previous engine installation project at Lerwick Power Station on Shetland, has provided a vast source of information such as engine unit price, planning, environmental impact, incorporation into existing infrastructure and project duration. This information has been used to prepare the RIIO-ED2 submission to replace our inefficient engines with alternative modern efficient models which are less polluting and deliver a reduction in greenhouse gas emissions.

From the supplier information currently available, it is estimated that the lead time for delivery of the engine units would be one year from placing an order, with the building and the infrastructure to support them developed during this time. It is anticipated that the project works would start in the first year of RIIO-ED2 with the final payments being in the second year.

Risk

As the two new engines will be installed as a new facility on an existing site, there will be no operational impact until they require to be incorporated into the current infrastructure e.g. mechanical and electrical service connections. As a result, the risk associated for the majority of the project is low and has no effect on the operation of either Battery Point or Arnish power stations in the build phase. During the connections detailed above, operational risk will increase; however, this will be planned and mitigated to ensure there is no effect on security of supply for customers e.g. during periods of low island demand when Battery Point is available.

In their role as our environmental regulator, SEPA would be included in all planning aspects of this project.

RIIO-ED2 BDPT figures

Figure 2 summarises the proposed volumes and costs associated with the investment.

Figure 2 - Proposed volumes and costs

Asset Category	Unit	2024	2025	2026	2027	2028	Total
Island Generation – Battery Point new diesel engine installation	#	1	1				2
	£m	£4.5m	£4.5m				£9.0m

Appendix C – Shetland supplementary information

The purpose of this appendix is to provide supplementary information to Ofgem on the following:

- Supplementary justification to support our Shetland-specific EJP and wider strategy.
- Confirmation of the Shetland re-opener window in Year 1 of RIIO-ED2.

The above information is considered essential in Ofgem's assessment of our business plan prior to final determinations. The information specifically addresses feedback from Ofgem raised during bilateral meetings, EJP feedback and supplementary questions.

Supplementary Justification to Support SSENs Shetland Specific EJP C25 - Shetland

SSEN EJP: 387/SHEPD/REGIONAL/SHETLAND – Shetland – HVDC Standby Project

DD Status: 'Partially Justified'

Supplementary information to support justification

We note Ofgem's request for further detail on the risk assessment of extending the life of Lerwick Power Station to 2035. This was also raised in our bilateral meeting with Ofgem on 1 August 2022.

In 2020, we utilised Mott MacDonald to assess a number of aspects of the Shetland solution, including the technical viability of extending the life of Lerwick Power Station (LPS) to allow it to perform the standby role. The details of this report were shared with Ofgem in December 2020. The analysis confirmed that LPS is capable of being used in the medium term as a standby power plant. In reaching that conclusion they identified a number of key risks and findings, which we have summarised, alongside our response to each. We refer Ofgem to the *Shetland Enduring Solution DSO Recommendation on Standby Arrangements* report that was submitted to them in December 2020, and which provides all the further detail on this.

Risk	Mott MacDonald finding	SHEPD view
Any significant changes required to transition LPS to standby role	Apart from modifications to facilitate remote operations, the decommissioning of the steam systems and possible addition of SCR, significant technical changes	Agree.

Risk	Mott MacDonald finding	SHEPD view
	to the power station are not required by the transition to standby operation.	
Compliance with emissions requirements	It is expected that the A Station engines will meet the future emissions requirements without provision for further abatement. The B Station engines will be required to comply with reduced emission limits after 2030, but it may be possible to obtain a derogation on the basis that fitting SCR systems will be technically and economically impractical. Failure to achieve such extended derogation would result in the need to retrofit expensive NOx abatement equipment (with corresponding ongoing costs).	Our current understanding is that emissions from LPS standby running will be managed within the applicable emissions limit values, including when taking account of a longer outage. Engagement is ongoing with SEPA in relation to this.
Fuel use	Once in standby mode, the use of heavy fuel oil (HFO) should be discontinued. In base load operation, the low unit fuel price of HFO may be justified, but this is not the case with the substantially reduced volume of generation post-HVDC connection going live.	LPS operations are currently being phased to light fuel oil use – this will be completed ahead of the transition to standby.
Decommissioning of steam systems	The steam systems and steam turbine should be decommissioned as these systems, when in circuit, delay start-up and the added complexity is not justified by the small increase in efficiency for a very much reduced volume of generation.	We agree with the recommendation to remove the steam turbine and parts of the steam system; we still need some steam to keep parts of the station warm so will retain some of the steam infrastructure.
Electrical configuration of load and speed of response during outage	The fact that 45% of the load is supplied by only two of the twelve outgoing feeders is an impediment to rapid re-energising of the system after an outage. The load could be more evenly distributed between feeders by the introduction of additional remote-controlled switching equipment. Reducing	This recommendation has been reviewed and no further action to be taken at this time. Remote-controlled switching equipment is already in place. We note the network configuration would be applicable regardless of the standby solution taken forward,

Risk	Mott MacDonald finding	SHEPD view
	the maximum feeder loading reduces the requirement for block load acceptance during fast start and so allows faster reinstatement of service after a forced outage.	whether fulfilled by existing assets or a new build solution.
A Station speed of response in an outage	The A Station engines can be started and loaded within 15 minutes after an unplanned outage if some of the systems are modified (oil pre-heating, cooling water pre-heating, automation –in the absence of full-time manning).	In the case of an outage, SHEPD would plan to utilise the Blackout Avoidance services.
B Station speed of response in an outage	To start and load the B Station engines within 15 minutes will require significant changes to the loading procedure and will have detrimental effect on engine wear and longevity. This may however not be a major concern since re-energising after an outage will be a rare event.	In the case of an outage, SHEPD would plan to utilise the Blackout Avoidance services.
Role of Blackout Avoidance equipment	Re-starting the system after an outage will be easily accomplished if the planned 50MW/45minute BESS and 20MW synchronous compensator (or technically equivalent solution) are installed, but other costs will still be incurred, including the cost of modifications to the LPS control systems and the decommissioning of the existing steam systems. The main purpose of the BESS would be to provide Blackout Avoidance that cannot be provided quickly enough by any other technology in the event of a HVDC trip. This cannot be achieved by the use of fast start-up engines, which will only serve to limit the duration of an outage once it has occurred.	We agree with the significance of the Blackout Avoidance equipment and are currently undergoing a tender process to procure this.
Manning of standby plant	It appears unlikely that full- time manning of the power plant in standby mode will be economic	In the short term SHEPD would intend to staff the station, keeping

Risk	Mott MacDonald finding	SHEPD view
	and remote control from an already manned control room is recommended, along with automation of some of the operations required. A period of transition is likely to be required before remote operation of the LPS can be fully implemented and this cost must be considered.	this under review in the early years of standby operation.
Precedents	Diesel engines have been successfully transited from base load to standby operation at a number of other power stations.	Agree

Shetland re-Opener for cost uncertainty (Consultation Question SSEN-Q10)

We agree that a re-opener is the most suitable mechanism for costs incurred in preparing, implementing and running a standby solution for Shetland. This is because we are currently carrying out a tender process for the provision of a standby solution service and until this process is completed there remains uncertainty on the level of costs.

As set out in our April re-submission, dated 22 April 2022, and discussed in the bilateral meeting with Ofgem on 1 August 2022, the re-opener window should be in Year 1 as we expect to start incurring costs from early 2023. We propose a second re-opener window at the end of the price control period, to allow for any adjustment required if the actual costs associated with the standby solution are +/-10% of our allowances.

In addition to this new Shetland re-opener, we also require two of the existing RIIO-ED1 Shetland reopeners to be retained for the RIIO-ED2 period. These re-openers are detailed in the table below.

RIIO-ED1 Shetland UM to be retained for RIIO-ED2	Description
Shetland extension fixed energy costs	<p>Costs: Third party contracts for Power Purchase Agreements with Sullom Voe; capital and operating costs for Lerwick Power Station; and operating the ANM system.</p> <p>Materiality threshold: +/-10% allowed expenditure</p>

RIIO-ED1 Shetland UM to be retained for RIIO-ED2	Description
Shetland variable energy costs	<p>Costs: Fuel costs and environmental permit costs for Shetland</p> <p>Materiality threshold: None – these items are treated as pass through.</p>

We will continue to work with Ofgem over the coming months as the project for implementing a standby solution for Shetland progresses.

Appendix D – NoS consultation questions

The purpose of this appendix is to provide an overview of all the Ofgem consultation questions that relate to our North of Scotland business plan and signpost where our responses can be found.

North of Scotland related Consultation Questions

Ofgem consultation question ref:	SSEN BPD Ref:	SSEN response form ref:
<p>SSEN-Q8</p> <p>What are your views on our proposals for SSEN's (in this case subsea cables) bespoke UMs?</p>	M13	<p>SSEN Annex Response Form 4:</p> <p>Adjusting baseline allowances for uncertainty</p>
<p>SSEN-Q9</p> <p>What are your views on our proposal for a HOWS UM re-opener? Do you think this is the most suitable mechanism to mitigate investment decision risk in this area?</p>	M13	<p>SSEN Annex Response Form 4:</p> <p>Adjusting baseline allowances for uncertainty</p>
<p>SSEN-Q10</p> <p>What are your views on our proposal for a Shetland re-opener to deal with the uncertain costs associated with Shetland? Do you think this is the most suitable mechanism to mitigate investment decision risk in this area?</p>	C25	<p>SSEN Annex Response Form 4:</p> <p>Adjusting baseline allowances for uncertainty</p>
<p>SSEN-CORE-Q83</p> <p>Do you agree with our proposed assessment approach for QoS and NoS Resilience costs?</p>	CV15	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>
<p>SSEN-CORE-Q91</p> <p>Do you agree with our proposed assessment approach for Property?</p>	C5	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>
<p>SSEN-CORE-Q92</p> <p>Do you agree with our proposed assessment approach for STEPM?</p>	C7	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>

Ofgem consultation question ref:	SSEN BPD Ref:	SSEN response form ref:
<p>SSEN-CORE-Q94</p> <p>Do you agree with our proposed assessment approach for HVPs?</p>	CV25	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>
<p>SSEN-CORE-Q96</p> <p>Do you agree with our proposed assessment approach for faults & ONIs?</p>	CV26	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>
<p>SSEN-CORE-Q99</p> <p>Do you agree with our proposed assessment approach for inspections and repair & maintenance?</p>	CV30 & CV31	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>
<p>SSEN-CORE-Q100</p> <p>Do you agree with our proposed assessment approach for NOCs other?</p>	C8	<p>Core Methodology Response Form 7:</p> <p>Delivering at lowest cost to energy consumers</p>

Appendix E - NoS SSEN reverse supplementary questions

The purpose of this appendix is to provide a consolidated list of all the North of Scotland-related reverse supplementary questions raised by us following receipt of Ofgem's DD.

North of Scotland-related reverse supplementary questions

SSEN reverse supplementary question reference	SSEN reverse supplementary question title
SSEN001	NoSR - Normalisations and adjustments
SSEN004	HOWS Uncertainty Mechanism parameters
SSEN010	Remote island generation
SSEN021	Pentland Firth East inclusion in HOWS Uncertainty Mechanism
SSEN023	Remote location generation capital costs – Battery Point
SSEN030	Subsea cable investment (CV7 & CV25)
SSEN037	Subsea cable Uncertainty Mechanism
SSEN041	Regional cost factors

Appendix F – NoS Business Plan data tables

The purpose of this appendix is to provide a consolidated list of all our North of Scotland-related Business Plan data tables, to ensure full alignment and appropriate treatment of the costs by Ofgem following the Draft Determinations.

North of Scotland-related Business Plan data tables

BPDT Ref	Description	Cost (£m)
<i>Islands</i>		
C9 – Core CAI	Submarine cable team	£7.5m
C2 – Connections within the price control	Island flights, accommodation and ferries	£0.1m
CV1 - Reinforcement (Primary Network)	Island flights, accommodation and ferries	£0.0m
CV2 - Reinforcement (Secondary Network)	Island flights, accommodation and ferries	£0.1m
CV7 - Asset Replacement	Island flights, accommodation and ferries	£0.2m
CV8 - Refurbishment non NARM	Island flights, accommodation and ferries	£0.0m
CV9 - Refurbishment NARM	Island flights, accommodation and ferries	£0.0m
CV26 – Faults	Island flights, accommodation and ferries	£0.3m
CV28 – ONIs	Island flights, accommodation and ferries	£0.1m
CV29 - Tree Cutting	Island flights, accommodation and ferries	£0.3m
CV30 – Inspections	Island flights, accommodation and ferries	£0.3m
CV31 - Repair and Maintenance	Island flights, accommodation and ferries	£0.2m
C9 - Core CAI	Island flights, accommodation and ferries	£0.2m
CV35 - Operational Training (CAI)	Island flights, accommodation and ferries	£0.3m
Subtotal	Island flights, accommodation and ferries	£2.2m

B PDT Ref	Description	Cost (£m)
CV26 – Faults	Helicopters	£0.5m
CV26 - Faults	Deployed staff prior to forecast severe weather events	£1.3m
C8 – Remote Generation Opex (Gross)*	OPEX – Remote generation operations and maintenance	£28.5m
CV15 – Remote Generation Capex	CAPEX – Battery Point DEG engine replacement	£9.0m
CV15 – Remote Generation Capex	CAPEX – Mechanicals and civils work – various sites	£5.3m
CV15 – Remote Generation Capex	CAPEX – Additional capacity installation at Bowmore	£0.5m
CV15 – Remote Generation Capex	CAPEX – Roof replacement due to condition and associated building works at Battery Point	£1.7m
Subtotal	Remote Generation Capex	£16.5m
Total islands		£56.5m

Sparsity		
C14 – Property Management	Property costs	£1.3m
C2 – Connections within the price control	Outposted staff	£1.5m
CV1 - Reinforcement (Primary Network)	Outposted staff	£0.2m
CV2 - Reinforcement (Secondary Network)	Outposted staff	£0.7m
CV7 - Asset Replacement	Outposted staff	£3.1m
CV8 - Refurbishment non NARM	Outposted staff	£0.6m
CV9 - Refurbishment NARM	Outposted staff	£0.0m
CV26 – Faults	Outposted staff	£3.8m

BPDT Ref	Description	Cost (£m)
CV28 – ONIs	Outposted staff	£1.0m
CV29 - Tree Cutting	Outposted staff	£4.5m
CV30 – Inspections	Outposted staff	£3.6m
CV31 - Repair and Maintenance	Outposted staff	£2.7m
C9 - Core CAI	Outposted staff	£2.2m
CV35 - Operational Training (CAI)	Outposted staff	£4.4m
Subtotal	Outposted staff	£28.2m
C2 – Connections within the price control	Longer driving times	£0.5m
CV7 - Asset Replacement	Longer Driving Times	£1.9m
CV26 – Faults	Longer Driving Times	£1.4m
CV29 - Tree Cutting	Longer Driving Times	£1.0m
CV30 – Inspections	Longer Driving Times	£0.4m
CV31 - Repair and Maintenance	Longer Driving Times	£0.3m
Subtotal	Longer Driving Times	£5.4m
C11 – Vehicles and Transport (CAI)	Additional vehicles	£3.8m
C13 – IT & Telecoms (Business Support)	Private Mobile Radio System and scanning telemetry	£11.2m
C13 – IT & Telecoms (Business Support)	Load-managed areas	£2.8m
Total sparsity		£52.6m

Submarine cables		
CV25 – HVP	HVP – Skye to South Uist (South Route)	£31.9m
CV7 – Asset Replacement	Proactive Asset Replacement Cables: Mainland - Kerrera 2	£2.7m

BPDT Ref	Description	Cost (£m)
	Jura - Islay	£4.5m
	Coll - Tiree	£7.6m
	Hoy - Flotta	£3.9m
	Loch Long (Dornie)	£2.0m
	Mull - Iona	£3.5m
	Mainland Orkney - Shapinsay	£5.1m
	Laxay - Kershader 2	£2.0m
	Loch A'Choire North	£4.0m
	Loch A'Choire South	£4.0m
	Kintyre - Gigha	£3.6m
	Mainland - Kerrera	£2.0m
	Subtotal	£45.1m
CV26 – Faults	Provision for x3 EHV & x3 HV Subsea Cable Repairs	£13.1m
CV30 – Cable Inspections	Provision for ROV Subsea Inspections	£16.8m
	Provision for Shore-end Cable Inspections	£0.2m
CV31 – Cable Repair & Maintenance	Shore-end Remedial Works	£2.1m
	Preservation & Maintenance	£2.2m
C5 – Property – Non Op	Strategic Cable Storage & Preservation	£1.4m
C7 – STEPM – Non Op	Subsea Cable Condition Monitoring	£1.4m
Total submarine cables		£114.0m

*“Remote generation OpEx request is £26m but for M25 this is shown as £28.5m (excluding the cost recoveries) as this is assessed at gross cost.

As per RIIO-ED2 Draft Determinations core methodology document, Shetland-related costs are technically assessed and therefore excluded from the TotEx modelling. In line with Core Methodology 7.62 we have removed this from the M25 table.

Other islands-specific factors		
Shetland		
C25 – Shetland	Third party contracts (Sullom Voe)	£26.0m
C25 – Shetland	Lerwick Power Station (CapEx & OpEx)	£27.9m
C25 – Shetland	NINES & ANM costs	£2.2m

North of Scotland Resilience is no longer included in M25 as it has been moved to CV19 Worst Served Customer (WSC) as noted in 7.303 of the Draft Determination core methodology. While this is not assessed on a disaggregated basis, given the materiality and disparity of spend between DNOs our view, as per our response to CQ87, is that WSC should be excluded from ToTex modelling.

Uncertainty Mechanism		
M13 – Uncertainty Mechanism	Subsea cables UM	£75.7m
M13 – Uncertainty Mechanism (subsea cable elements)	Hebrides & Orkney Whole System (subsea cables only): Skye to Uist (North Route) Pentland Firth West (x1 Cable) Mainland Orkney - Hoy South (3) Eriskay - Barra 2 South Uist - Eriskay	£25.9m £26.2m £4.9m £8.9m £4.6m
TBC	Shetland Enduring Solution	£42.2m

Appendix G – NoS cost-modelling summary

The purpose of this appendix is to advise Ofgem that an overview of the discrepancies identified between our base plan submission and Ofgem's DD are contained within Annex 5 – Material DD Issues and Impacts on SSEN.

It is envisaged that the additional clarity and recommendations will support the appropriate resolution as part of Final Determinations.