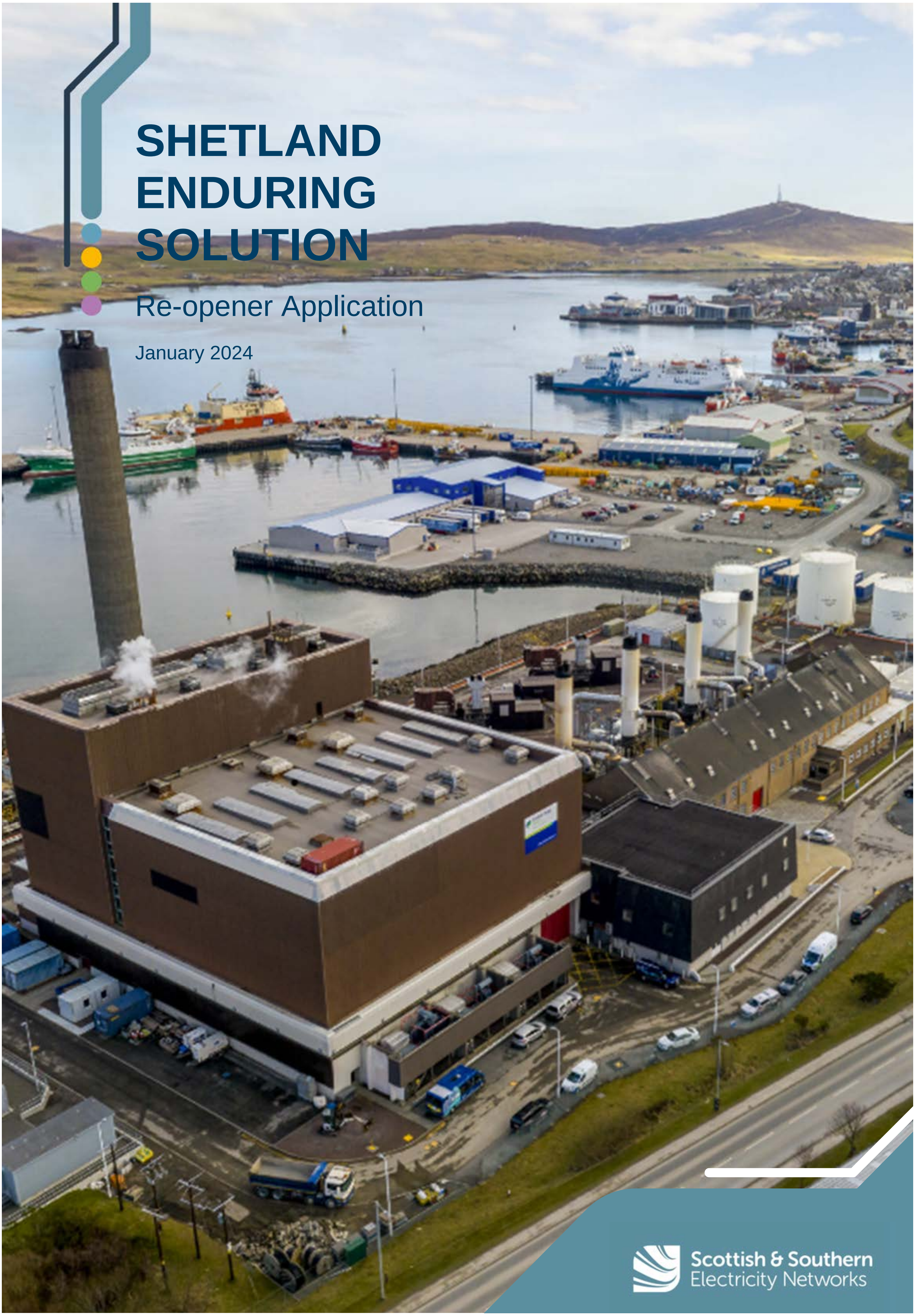
SHETLAND ENDURING SOLUTION

Re-opener Application

January 2024



Scottish & Southern Electricity Networks

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1. ABBREVIATIONS

Acronym	Definition	Acronym	Definition
ANM	Active Network Management	LPS	Lerwick Power Station
BESS	Battery Energy Storage System	MDG	Mobile Diesel Generation
CBA	Cost Benefit Analysis	MTTR	Mean Time To Repair
CfD	Contract for Differences	MW(h)	Megawatt (hour)
CT	Consumer Transformation	NGESO	National Grid Electricity System Operator
D-Code	Distribution Code	NINES	Northern Isles New Energy Solutions
DFES	Distribution Future Energy Scenarios	NPV	Net Present Value
D-FRT	Distribution Fault Ride Through	PPA	Power Purchase Agreement
DG	Distributed Generation	PRB	Project Review Board
DNO	Distribution Network Operator	RTS	Radio Tele-Switching
FCO	First Circuit Outage	SEPA	Scottish Environment Protection Agency
FEU	Forced Energy Unavailability	SES_t	Shetland Enduring Solution term
GB	Great Britain	SEU	Scheduled Energy Unavailability
GD	Group Demand	SHEPD	Scottish Hydro Electric Power Distribution
GF	Grid Forming	SSEN	Scottish and Southern Electricity Networks
GIS	Geographic Information System	ST	System Transformation
GSP	Grid Supply Point	SVT	Sullom Voe Terminal
GW	Gigawatt	UM	Uncertainty Mechanism
HVDC	High Voltage Direct Current		

2. EXECUTIVE SUMMARY

The purpose of this document is to set out the needs case, the options considered and our recommendation as part of our formal application under Special Licence Condition 3.2 Part P of SHEPD's Special Licence Conditions to modify the Shetland Enduring Solution term (SES_t).

Shetland is currently an islanded electricity network. As part of a whole system solution developed with SSEN Transmission, Shetland will soon be connected to the GB electricity system for the first time, enabling Lerwick Power Station (LPS) to move from full duty operation to standby mode. The new HVDC link is a single circuit therefore in the event of an unplanned outage, a solution is required to ensure security of supply is maintained.

For the standby solution to maintain supplies on Shetland it must provide two elements: (i) the ability to ride through any full system Transmission fault; and (ii) the ability to provide for the demand on Shetland for up to 45 minutes until LPS is up and running. Failure to provide both elements would result in a blackout across Shetland with an estimated 3-4 hours full supply restoration time.

As part of the RIIO-ED2 Final Determination for Shetland, Ofgem provided the following:

- Confirmation of allowances for continuing to run and extend the life of LPS in standby mode;
- A new licence condition, Special Condition 3.16, providing for SHEPD's contribution to the HVDC link;
- A continuation of the licence condition, Special Condition 6.1 Part C, that allows fuel costs and environmental permit costs for Shetland to be treated as pass through costs;
- Continuation of the Shetland Extension Fixed Energy Costs re-opener from RIIO-ED1 under Special Licence Condition 3.2 Part Q; and
- A new Uncertainty Mechanism (UM) in the form of a bespoke re-opener for the ***Shetland Enduring Solution*** under Special Condition 3.2 Part P.

This UM submission is in relation to the ***Shetland Enduring Solution*** re-opener only. No allowances were provided for the Shetland Enduring Solution as part of SHEPD's baseline allowances for RIIO-ED2 as at that stage we had not completed the tendering process, so the costs were uncertain. As the tendering process is now sufficiently progressed, we are now able to provide an update on costs, technical justification and overall approach, with a preferred option for the ***Shetland Enduring Solution***.

In this UM submission, we detail five options for a standby solution[1]:

1. Standby Equipment – Asset Purchase – 2025/26 Delivery
1b. Standby Equipment – Asset Purchase – 2026/27 Delivery
2. Standby Equipment – Service – Without Trading
2b. Standby Equipment – Service – With Trading
3. Do Nothing

1 Five additional rejected options considered under a wider technical review are outlined in Appendix D.

Through the CBA (Attachment 1) it has been determined that the most economic and efficient solution for the standby solution is **Option 2 – retaining LPS as the standby generation and to procure fault ride-through and blackout avoidance equipment as a service, for a 10-year period, with no trading.** The no trading option has been selected as the option to progress for funding. This is because there are multiple factors which will impact the revenue from trading and rather than commit an estimate into the service contract for the standby solution (which would inevitably be conservative), we have reached an agreement with the service provider whereby we log up trading revenues with a percentage of those revenues taken off the costs of the service each year. Where there are any reductions in costs as a result of trading, these will be passed to consumers in the true-up at the end of RIIO-ED2. See Appendix G and Attachment 5 for further information on trading.

The expected cost to deliver the recommended solution for RIIO-ED2 is £27.13m (excluding all costs already funded through the RIIO-ED2 Final Determination and an estimated link contribution of £251m[2]). Table 1 below details the expected expenditure in each year. We did not receive any funding for the Shetland Enduring Solution in RIIO-ED2 and as such £27.13m trigger of £2.16m under Special Licence Condition 3.2 Part P.

Table 1 - RIIO-ED2 Shetland Enduring Solution Costs

Cost category	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Shetland Enduring Solution costs (SESt)	£m	4.19	0.84	4.65	8.72	8.72	27.13
Note: The above table covers the SESt RIIO-ED2 costs only. As the proposed service will run for a 10-year period, approval of this UM funding will commit us and consumers to the full 10-year contract. As such, the full-service period costs are included in the CBA (£92.55m total). These costs will be included in our baseline costs for RIIO-ED3 and RIIO-ED4 accordingly.							

The solution is dependent on the timing of delivery of the Shetland transmission system, with the HVDC link expected to be delivered during 2024 and the wider system and GSP connection to be completed by November 2025, in accordance with the dates that have been advised to us by NGESO and SSEN Transmission. We await the updated connection agreement to reflect this date.

The solution delivers the following:

- It is the lowest cost, compliant standby solution to secure Shetland demand, meeting P2/8 requirements now and later in ED2 when demand is projected to increase from Class of Supply C to Class of Supply D.
- It will ensure that Shetland customers continue to experience an equivalent standard of security of supply to that currently in place and aligned to the planning standards which apply across Great Britain.
- It is modular in nature and can be augmented to meet future demand and generation requirements for Shetland with flexibility to transition to a lower carbon standby solution.

[2] Subject to change, further to confirmation of the final link cost value applied in the contribution calculation.

- It has resulted in an innovative configuration of technologies for fault ride-through blackout avoidance, provided by the market as a service.
- It gives the service provider the ability to trade/stack benefits from any spare capacity in the BESS to reduce the overall cost of the service to our customers. It is a no regret investment which forms the starting point for multiple pathways which can deliver security of supply to Shetland out to 2050 and beyond. More detail on the long-term approach for Shetland is set out in Section 8 and Attachment 2.

3. INTRODUCTION

This document and the enclosed appendices constitute Scottish Hydro Electric Power Distribution (SHEPD)'s re-opener application for a change to the Shetland Enduring Solution (SES_t) allowances under Part P of Special Licence Condition 3.2. No allowances were provided for SES_t in RIIO-ED2 as we were still undergoing the tender process and were therefore unable to provide certainty of costs. We have now completed this process and provide detail on our recommended standby solution for Shetland in this submission. This means there will be a change in the costs we expect to incur relative to the previous value of zero. The cost we expect to incur in ED2 is £27.13m, which exceeds the materiality threshold of £2.16m.

In line with Special Condition 3.2 Part P, we are submitting this re-opener application in the window of 24th-31st January 2024. This application sets out: the scope of work we propose to carry out associated with the Shetland Enduring Solution; the modifications to the value of SES_t being sought; the basis for calculating the modifications to the allowances and the profiling; and the detailed supporting evidence that is needed for Ofgem to review our application and make an informed decision.

The application is confined to costs expected to be incurred that are not otherwise funded by the special conditions and to costs that are expected to be incurred on or after 1 April 2023.
Table 2 below maps out which sections of the application relate to the individual requirements as set out in Special Condition 3.2 Part P as well as those set out in Chapter 3 of Ofgem's Re-opener Guidance and Application Requirements Document.

Table 2 - Reference requirements

Reference	Requirement	Where to find in our submission
SpC 3.2 Part P 3.2.112 (a)	There has been a change to the costs the licensee has incurred or expects to incur related to the SES, relative to any previous allowances for such costs, that exceed the Materiality Threshold.	Shetland Enduring Solution Re-opener Application **Section 3: Introduction**
SpC 3.2 Part P 3.2.114	(a) Sets out how the requirement in paragraph 3.2.112 has been fulfilled	Shetland Enduring Solution Re-opener Application **Section 3: Introduction**
SpC 3.2 Part P 3.2.114	(b) Sets out the scope of work the licensee has carried out or proposes to carry out associated with the Shetland Enduring Solution	Shetland Enduring Solution Re-opener Application **Section 5**: **Option 2 Standby Solution Procured as a Service – without trading**

Reference	Requirement	Where to find in our submission
SpC 3.2 Part P 3.2.114	(c) Sets out any modifications to the value of SESt in Appendix 1 being sought	Shetland Enduring Solution Re-opener Application **Section 3: Introduction**
SpC 3.2 Part P 3.2.114	(d) Explains the basis for calculating any modifications requested to allowances and the profiling of those allowances	**Attachment 1** – Shetland Enduring Solution CBA
SpC 3.2 Part P 3.2.114	(e) Provides such detailed supporting evidence as is reasonable in the circumstances	Shetland Enduring Solution Re-opener Application and all attachments.
SpC 3.2 Part P 3.2.117	(c) the modification to allowances is efficient	Shetland Enduring Solution Re-opener Application – **Section 5: Standby Options Considered** **Attachment 1** – Shetland Enduring Solution CBA.
Re-opener Guidance Document – Needs case and preferred option	Alignment with overall business strategy and commitments.	Shetland Enduring Solution Re-opener Application – **Section 5: Standby Options Considered**
Re-opener Guidance Document – Needs case and preferred option	Demonstration of needs case / problem statement	Shetland Enduring Solution Re-opener Application **Section 4**: **Needs Case.**
Re-opener Guidance Document – Needs case and preferred option	Consideration of options and methodology for selection of the preferred option	Shetland Enduring Solution Re-opener Application **Section 5**: **Standby Options Considered.**
Re-opener Guidance Document – Needs case and preferred option	The preferred option	Shetland Enduring Solution Re-opener Application **Section 7: Recommended Option**
Re-opener Guidance Document – Needs case and preferred option	Project delivery	Shetland Enduring Solution Re-opener Application **Section 12: Project deliverability and monitoring**
Re-opener Guidance Document	Stakeholder engagement and whole system opportunities	Shetland Enduring Solution Re-opener Application **Section 11**: **Validate investment plans and benefits with stakeholders** and **Appendix G: Energy Trading**

Reference	Requirement	Where to find in our submission
Re-opener Guidance Document	Cost information	**Attachment 1** – Shetland Enduring Solution CBA Shetland Enduring Solution Re-opener Application **Section 9: Changes since draft submission to Ofgem, Section 10: Ongoing uncertainty, Section 6 Summary of cost benefit analysis**
Re-opener Guidance Document	Cost benefit analysis and engineering justifications	**Attachment 1** – Shetland Enduring Solution CBA **Attachment 3** – Shetland Enduring Solution Long Term CBA

4. NEEDS CASE

There are currently over 14,000 distribution customers on Shetland. In 2020/21 peak demand was 43.5 MW. At present there is no interruption of supply to the Shetland islands as a result of a First Circuit Outage (FCO) as defined under P2/8, either as a result of planned or unplanned outages. This is because there is always additional generation running between LPS, Sullom Voe Terminal (SVT) and Distributed Generation (DG) such that the loss of any one generator, or a circuit/transformer fault, will not result in a blackout for the entire Shetland network. The existing combined network and generation arrangements provide security of supply such that island-wide blackouts have not been experienced in the last 30 years.

Our load estimates and Distribution Future Energy Scenarios (DFES) indicate that the Group Demand (GD) for Shetland is likely to increase above 60 MW by 2028/29 (potentially earlier) and Shetland will become Class of Supply D for Engineering Recommendation P2/8. This will require that for FCOs a minimum of 40.4 MW of demand is met immediately and the entire GD to be met within 3 hours.

In the absence of suitable standby arrangements, customers on Shetland would experience a blackout for around 3-4 hours each time there is an unplanned outage on the transmission system. This is because without the standby arrangement, LPS would have to recover the system from a black start scenario.

The potential impact of a black start is summarised in Table 3 below. This is based on the defined HVDC Link availability as provided by SSEN Transmission: [redacted] based on reliability of similar links. This means we are estimating around [redacted] black start situations over the 10-year period for the standby solution. The assumption in Table 3 is that LPS is available to recover the system from a black start scenario.

Table 3 - Various quantitative measures of black start

Measure to quantify	Notes	Quantified impact over 10 years £m (2020/21 prices, undiscounted)
Customer Interruptions and Customer Minutes Lost	Based on ED2 Interruptions Incentive Scheme rates and an average of 3 hours off for all customers	1 trip pa- £5.4m 2 trips pa- £10.7m 3 trips pa- £16.1m
Value of Lost Load (VOLL)	Based on methodology for VOLL detailed in section 5 - range shown is for most conservative and aggressive assumptions of VOLL	1 trip pa- £12m-32m 2 trips pa- £25-64m 3 trips pa- £37-96m
[redacted]	[redacted]	[redacted]
[redacted]	Based on ED2 VOLL rates and an average of 3 hours off for all customers	[redacted]

Table 3 highlights the significant impact of a black start scenarios on Shetland over the 10-year period, excluding the wider economic and social impact on Shetland. We consider that this provides clear supplementary evidence of the needs case for a Standby solution.

Following optioneering and detailed analysis, the proposed scope of works to deliver the security of supply requirements on the Shetland islands is as follows:

- Maintain an extension of existing security of supply arrangements from April 2023 until the new GSP and Shetland transmission system are available; expected to be November 2025 – *funding approved to run to November 2023, additional funding will be required to run to November 2025, to be captured under Shetland Extension Fixed Energy Costs re-opener at the end of RIIO-ED2.*
- Transition the existing Lerwick Power Station from full duty to standby use – *funding approved under RIIO-ED2 Business Plan.*
- Procure reliable and innovative fault ride through and blackout avoidance equipment which will have the ability to maintain frequency, voltage and provide stability/short circuit infeed, maintaining supply, until LPS standby generation can be started – *funding requested in this submission*.
- Contract for the provision of a new GSP on Shetland by NGESO / SSEN Transmission, connecting the distribution and transmission systems, and associated preparatory works – *funding exists under RIIO-ED2*.

[redacted].

- Facilitate several minor distribution network developments to facilitate the GSP connection and supply to / from the transmission system, including 33kV circuit breakers and underground cabling – *funding exists under RIIO-ED2*.

Our proposal also identifies the need for 'fault ride-through' functionality to manage any imbalances or interactions between the transmission and distribution systems immediately upon an outage occurring, driven primarily by the significant amount of transmission wind that may be connected. Following a successful procurement exercise, the final technical design is now being developed through engagement with the service provider and analysis by ourselves and SSEN Transmission. This has identified the specific technical solution required for the fault ride-through and the blackout avoidance scheme will require an AC Chopper and a Grid Forming (GF) Battery Energy Storage System (BESS) and its associated costs to procure it as a service. Further detail on the technical feasibility of the solution is provide in Section 7.

Finally, our contribution towards the transmission link has been approved separately by Ofgem but is referenced in this paper for completeness. The mechanism for this is set out in Special Condition 3.16 Shetland Link Contribution.

5. STANDBY OPTIONS CONSIDERED

Summary of Core Standby Options

Table 4 below provides a high-level summary of the two core standby options under consideration – each with two sensitivities – along with the associated advantages and disadvantages. These options were selected to be put through to a CBA by assessing a longer list of options against the following criteria:

(i) Meets the technical requirement and avoids black-outs;
(ii) Deliverability in the required timescales;
(iii) Whether the option was proposed in response to the tender;
(iv) If the option is practical to implement; and
(v) Cost

As a result of the above assessment, a number of options were rejected and not taken forward to CBA. These are detailed in Appendix D – Additional options rejected.

The options put forward align with our overall strategy and business commitments as set out in our RIIO-ED2 Business Plan. See Annex 8.1 of SSEN Distribution's RIIO-ED2 Business Plan – Scottish Islands Strategy[4] for further detail.

These core standby solutions would meet demand for the duration of any outage. Common to each option, LPS would be converted from full duty operation to standby mode and be complemented by the instantaneous

4 A_8.1_ScottishIslands_CLEANFINAL_REDACTED.pdf (ssenfuture.co.uk)

response of the distribution fault ride-through (D-FRT) and blackout avoidance equipment for 10 years. The equipment rating has been based on the peak demand from the CT DFES scenario to provide:

- Distribution Fault Ride Through (D-FRT).
- Island mode stability.
- Energy storage for up to 45 minutes.

It would require connection of the AC Chopper and BESS to the 33 kV network in order to maximise its effectiveness and reliability whilst minimising the connection costs and any associated reinforcements.

Only costs associated with D-FRT and blackout avoidance equipment have been included below, costs associated with the operation of LPS and the connection of Gremista GSP have not been included in the following costs as they have already been approved within the RIIO-ED2 Final Determination.

A more detailed description of each option is provided within the sub-sections which follow, and full details are provided in the CBA in Attachment 1.

Demand flexibility solutions have also been considered in this project to potentially reduce the amount of standby equipment, services and generation required. A call for flexibility services on Shetland was published on our website to identify interest and a tender exercise was run in December 2021, however there was insufficient interest to impact on the requirements of the standby solution for Shetland. Future requirements to augment the standby solution, if required, will again consider flexible solutions, and call for interest would be published on the website accordingly.

A third option 'Do Nothing' is also included in Table 2 and within the CBA. If Shetland was connected to the Transmission system without a Standby Solution, an unplanned HVDC link outage would result in a full island blackout on Shetland and supply interruptions to over 14,000 customers. If permanent standby generation is retained without D-FRT or blackout avoidance equipment being deployed, then supply interruptions will occur for network faults/outages. This outcome is non-compliant with P2/8 and the D-Code and would require a derogation. This outcome would also result in damage to customer confidence, with customers on Shetland receiving a lower standard of security of supply following the introduction of the HVDC link solution (which is part funded by SHEPD).

Table 4 – Summary of Options[5]

Options	Description	Advantages	Disadvantages
1. Asset purchase of Standby Solution. Delivery in 2025/26. LPS used for standby generation.	SHEPD asset purchase of AC Chopper and BESS to provide D-FRT, maintain frequency, voltage and provide stability/short circuit infeed and avoid a blackout until LPS standby generation can be started. Convert LPS from full duty to operate in standby mode.	No blackout for HVDC link outage. Utilisation of renewable DG to offset carbon during island mode running. Future use to provide services in island mode. Can extend asset life by between 15 to 20 years with augmentation.	Higher capital costs. Medium delivery time. Would require derogation (Category C exemption) under Standard Licence Condition 31D Prohibition on Generating by Licensee to own generation. Lower whole system efficiency as cannot be used to trade or stack other benefits as this could distort the market. Elements may not be required post 10 years resulting in stranded assets. Would result in a delay beyond November 2025.
1b. Asset purchase of Standby Solution. Delivery in 2026/27. LPS used for standby generation.	One year delay to SHEPD asset purchase of AC Chopper and BESS to provide D-FRT, maintain frequency, voltage and provide stability/short circuit infeed and avoid a blackout until LPS standby generation can be started. Convert LPS from full duty to operate in standby mode.	Achievable delivery time. Detailed specifications would be developed. No blackout for HVDC link outage. Utilisation of renewable DG to offset carbon during island mode running. Future use to provide services in island mode. Can extend asset life by between 15 to 20 years with augmentation.	High capital cost and overall cost. Longer delivery time. Would require derogation (Category C exemption) under Standard Licence Condition 31D Prohibition on Generating by Licensee to own generation. Lower whole system efficiency as cannot be used to trade or stack other benefits as this could distort the market.
2. Standby Solution procured as a Service – without Trading.	Procure a third-party service contract to deploy additional standby equipment to maintain frequency,	No blackout for HVDC link outage. Low capital costs. Shorter delivery time.	An assumption on trading benefit is not locked in as part of service agreement but used to net of service costs over time.

5 We highlight that our previous Engineering Justification Paper and expert third party analysis considered the impact of procuring additional plant and services to accommodate high demand scenarios across the LPS, HS and MS options, and concluded that LPS remained the preferred option.

Options	Description	Advantages	Disadvantages
LPS used for standby generation.	voltage and provide stability/short circuit infeed until LPS standby generation can be started. Service provider is NOT able to trade/stack benefits. Convert LPS from full duty to operate in standby mode.	Utilisation of renewable DG to offset carbon during island mode running. No long-term requirement to maintain the Standby Equipment assets or de-commission it after 10-year contract period.	Requires future Flexibility tender after 10-year contract period if no further network developments.
2b. Standby Solution procured as a Service – with Trading. LPS used for standby generation.	Procure a third-party service contract to deploy additional standby equipment to maintain frequency, voltage and provide stability/short circuit infeed until LPS standby generation can be started. Service provider can trade/stack benefits. Convert LPS from full duty to operate in standby mode.	Service provider can trade/benefit stack to offset the price paid. No blackout for HVDC link outage. Low capital costs. Shorter delivery time. Utilisation of renewable DG to offset carbon during island mode running. No long-term requirement to maintain the Standby Equipment assets or de-commission it after 10-year contract period.	Requires future Flexibility tender after 10-year contract period if no further network developments. Likely to lead to conservative estimates on likely trading revenues.
3. Do Nothing	No fault ride through procured to secure demand. Convert LPS from full duty to operate in standby mode.	Lower cost.	Blackouts on Shetland every time an outage occurs on the transmission network. See Section 4 for further detail on the impacts of blackouts.

Option 1: Asset purchase of Standby Solution. Delivery in 2025/26

Under this option, it is proposed to retain LPS and convert it from full duty to standby operation to provide the long standby generation. The additional D-FRT and blackout avoidance equipment will be procured as an asset purchase.

If an unplanned transmission outage was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 45 minutes to bring LPS generation online and restore supplies to the majority of Shetland, including network switching and balancing. In addition, to avoid customers being off supply while diesel generators at LPS are started, it is proposed to deploy D-FRT and blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation is able to generate on to the system).

All elements of this option are modular and can be augmented with additional modules or Mobile Diesel Generation (MDG), additional engines or storage / flexible services at LPS if a higher demand forecast or future large new connections materialise. The costs assume an AC Chopper and Grid Forming (GF) Battery Energy Storage System (BESS) will constitute the D-FRT and blackout avoidance equipment based on DFES CT.

Expected SES_t in RIIO-ED2 as calculated in CBA: £66.77m

Expected NPV cost (10 years) as calculated in CBA: -£43.68m[6]

Option 1b. Asset purchase of Standby Solution. Delivery in 2026/27

Option 1b is a sensitivity of Option 1 with an additional year's delay until the Standby Solution is commissioned. This reflects potential credible delays which could occur in the time required for SHEPD to carry out a regulated tender, contractual negotiations, and delivery of the asset purchase.

Expected SES_t cost in RIIO-ED2 as calculated in CBA: £64.64

Expected NPV cost (10 years) as calculated in CBA: -£49.03m[6]

Option 2: Standby Solution procured as a Service – without Trading

The most viable alternative identified is to secure the D-FRT and blackout avoidance equipment as a service from a third party, but with no savings assumed as a result of trading/benefit stacking committed into the upfront service costs. There is uncertainty on the level of revenue that trading/benefit stacking will result in for the service provider whilst they are providing the blackout avoidance service.

Similar to the previous options, if an unplanned outage was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 45 minutes to bring LPS generation online and restore supplies to the majority of Shetland,

[6] Expected NPV includes total costs assessed in CBA, i.e. estimated LPS costs in addition to SES_t costs.

including network switching and balancing. Similarly, to avoid customers being off supply while diesel generators are started, it is again proposed to deploy D-FRT and blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation starts up).

As with previous options, the ability to retain LPS for 10 years will provide the option to flex to a low carbon solution or second network links if/when available. The 10-year service also provides the benefit of allowing additional options to be considered after this point when there is more certainty in terms of other generators and flexible options on Shetland.

This option is also modular and can be augmented with additional modules or MDG, additional engines or storage/flexible services at LPS if a higher demand forecast or future large new connections materialise. The cost are for the tendered solution of an AC Chopper and grid forming BESS will provide the D-FRT and blackout avoidance services based on DFES CT.

Expected costs in RIIO-ED2 as calculated in CBA: £27.13m

Expected NPV cost (10 years) as calculated in CBA: -£30.59m[7]

Option 2b: Standby Solution procured as a Service – with Trading

An alternative identified is to secure the D-FRT and blackout avoidance equipment as a service from a third party.

Similar to the previous options, if an unplanned outage was to occur (e.g. for a fault on the HVDC link) then it is estimated to take 45 minutes to bring LPS generation online and restore supplies to the majority of Shetland, including network switching and balancing. Similarly, to avoid customers being off supply while diesel generators are started, it is again proposed to deploy D-FRT and blackout avoidance equipment to fill the gap in supply. This will consist of island mode stability equipment (to provide voltage support, inertia, and short circuit current) and energy storage/demand side response (to provide sufficient energy until generation starts up).

Option 2 is a viable solution to secure a service for the D-FRT and blackout avoidance equipment. Comparable benefits exist as for the previous Options with regards to the opportunity to develop a hybrid solution for island mode operation. As with previous Options, the ability to retain LPS for 10 years will provide the option to flex to a low carbon solution or second network links if/when available. The 10-year service also provides the benefit of allowing additional options to be considered after this point when there is more certainty in terms of other generators and flexible options on Shetland.

This option is also modular and can be augmented with additional modules or MDG, additional engines or storage/flexible services at LPS if a higher demand forecast or future large new connections materialise. Once

[7] Expected NPV includes total costs assessed in CBA, i.e. estimated LPS costs in addition to SES_t costs.

again, the costs assume an AC Chopper and grid forming BESS will provide the D-FRT blackout avoidance services based on DFES CT.

Expected cost in RIIO-ED2 as calculated in CBA: £25.07m

Expected NPV cost (10 years) as calculated in CBA: -£29.57m[8]

Option 3: Do Nothing

This option would result in communities on Shetland receiving a poorer service than they currently do and have done for many decades, and a poorer service in comparison to the rest of Great Britain. It would result in a full island blackout on Shetland whenever there is an unplanned outage of the Transmission connection, which based on availability data from ESO, could be [redacted]. This option would require a derogation from the P2/8 planning standards from Ofgem. We have included this option with the CBA to provide some additional context however, we do not believe that it is a viable option given the political, economic and social impact it would have on Shetland.

In the event of a black start scenario on Shetland as a result of a Transmission outage, the Distribution network would be brought back online progressively. LPS would operate the system in Island mode to restore a reliable network and supply of electricity to Shetland by following a prescribed approach undertaken by LPS operating as the System Operator in island mode. This would be carried out as follows:

- 11kV circuits re-energised to ensure that LPS and the hospital on Shetland are restored back to normal supplies;
- 33kV circuits re-energised targeting critical and high customer number circuits; and
- Progressively build up the network ensuring generation is running effectively in advance of closing in circuits.

We carried out a live simulation test of a black start scenario in May 2023 to gain an understanding of the likely time it would take for full supply restoration to all customers in the event of a blackout. Our results showed that it would likely take up to 4 hours before all customers were restored. We have assessed the key areas of impact of a 4-hour blackout on Shetland below.

As part of the connection agreement with SSEN Transmission for the HVDC Transmission Link, there is a memorandum of understanding which sets out the expected failure rate of the HVDC link, based on similar converters and cables in service, of the same age and condition. [redacted]

[8] Expected NPV includes total costs assessed in CBA, i.e. estimated LPS costs in addition to SES_t costs.

Impact of black start scenario on the Shetland economy and customers

Shetland is a remote Island with the main employment for islanders coming from Oil and Gas, Fishing Industry, Agriculture and Tourism. Each of these relies upon a secure supply of electricity with the impact on some areas of loss of that supply greater than others.

DOMESTIC CUSTOMERS

Customers on Shetland are some of the most remote in GB and are subject to some of the most extreme weather. Of the circa 14,000 households on Shetland, 2,000 are classed as vulnerable, and an additional 5,000 customers on Shetland have electric heating. Given the remoteness of some of the housing on Shetland, providing support to these customers within a 4-hour timescale would be challenging and would mean vulnerable customers could be without electricity for a number of hours.

OIL AND GAS

[redacted]

FISHING INDUSTRY

This is the second biggest industry on Shetland, with a value of £110m in 2021[9] and home to 179 commercial boats.[10] Shetland-based fishing boats accounted for 17% (by weight) of all the fish and shellfish landed by UK boats. Much of the output from this industry is high quality produce, and to retain high market prices requires

9 Shetland-Fisheries-Statistics-2021

10 Shetland in Statistics 2017

fast and constant refrigeration. Any interruption to that refrigeration would likely have a significant impact on the value of the catch and could be catastrophic for such a key industry and employer on Shetland.

Expected cost in RIIO-ED2: £5.40m

Expected NPV cost (10 years): -£127.75m

6. SUMMARY OF COST BENEFIT ANALYSIS

This section of the report provides an overview of the expected costs for each option from the CBA undertaken. This represents the output of the detailed exercise undertaken to support the recommended investment strategy that is detailed within this submission.

The results of this financial analysis are described below:

Summary of Capital Costs

It can be seen in Table 5 that excluding Option 3 (which we do not consider to be viable as detailed in Section 5), the least cost option for spend in RIIO-ED2 is Option 2b. It also shows that if the estimation of trading/benefit stacking does not materialise, that Option 2 is the second cheapest at full cost for the service. Given the uncertainty over the level of trading/benefit stacking, we are recommending Option 2.

Table 5: Summary of SES_t costs of options

Options	Unit	23/24	24/25	25/26	26/27	27/28	Total
1. Asset purchase of Standby Solution. Delivery in 2025/26.	£m	8.92	20.81	32.97	1.93	2.13	66.77
1b. Asset purchase of Standby Solution. Delivery in 2026/27.	£m	8.92	0.84	20.81	32.13	1.93	64.64
2. Standby Solution procured as a Service – without Trading.	**£m**	**4.19**	**0.84**	**4.65**	**8.72**	**8.72**	**27.13**
2b. Standby Solution procured as a Service – with Trading.	£m	4.19	0.84	3.93	7.88	8.23	25.07
3. Do Nothing	£m	5.40	-	-	-	-	5.40

Cost Benefit Analysis Comparisons

The CBA showed that over a 10-year service contract procuring the blackout avoidance equipment as a service, with the addition of trading/benefits stacking, was the best option (Option 2b). This considers the NPV after 10 years.

Although Option 1 has been included, it is explained that delivery in time to connect to the HVDC link is very unlikely and therefore Option 1b is a better representation at this time. When comparing to Option 1b, even without trading, the service-based approach is preferred (Option 2). When considering the NPV after 45 years Option 2b, followed by Option 2 are still the preferred, when compared with Option 1b. As explained above, Option 2 is selected on the basis that the potential revenue from trading/stacking benefits for the service provider are uncertain. Consumers will benefit from any reductions in costs to us as a result of trading via the true-up at the end of RIIO-ED2.

Table 6: Comparison of CBA of options

Options	NPV After 10 Years (£m)[11]	NPV After 45 Years (£m)[12]
1. Asset purchase of Standby Solution. Delivery in 2025/26. LPS used for standby generation.	-43.68	-98.36
1b. Asset purchase of Standby Solution. Delivery in 2026/27. LPS used for standby generation	-49.03	-112.84
2. Standby Solution procured as a Service – without Trading. LPS used for standby generation	-30.59	-96.59
2b. Standby Solution procured as a Service – with Trading. LPS used for standby generation	-29.57	-93.95
3. Do Nothing	-127.75	-130.59

[11] Expected NPV includes total costs assessed in CBA, i.e. estimated LPS costs in addition to SES_t costs.

7. RECOMMENDED OPTION

Option 2: Standby Solution procured as a Service – without Trading

Through the CBA it has been determined that the most economic and efficient solution for the standby solution is Option 2 – retaining LPS as the standby generation and to procure fault ride-through and blackout avoidance equipment as a service, for a 10-year period, with no trading.

Option 2 is recommended because it is the most efficient, compliant solution to secure the Shetland demand, whilst also providing the opportunity for future price reductions as a result of the battery being traded by the service provider. In addition, it preserves future flexibility to transition to a lower carbon standby solution when one becomes available. The chosen option is modular in nature and can be augmented to meet future new connections and the changing future demand and generation requirements for Shetland. The no trading option has been selected as the option to progress with funding for on the basis that trading revenues are uncertain and committing to an assumption of those revenues into the upfront service costs would lead to an overly conservative assumption which would not be customers interests. As described above, we have reached an arrangement with the service provider whereby trading revenue will be declared and used to net off the service costs.

Where there are any reductions in costs as a result of trading, these will be passed to consumers in the true-up at the end of RIIO-ED2. See Appendix G and Attachment 5 for further information on trading.

Procurement

Engagement with the market

Engagement was undertaken with the market in 2020 on blackout avoidance technologies. First, a Pre-Qualification Questionnaire (PQQ) stage of the procurement process was conducted to identify and procure appropriate technical solutions to meet the blackout avoidance requirements (inertia and fast response power met through use of synchronous compensation and energy storage). Subsequently a two-stage Invitation To Tender (ITT) was carried out; Round 1 short listed successful bidders in early 2022 and Round 2 selected preferred bidder in early 2023. We also included Shetland in a call for flexibility services to identify potential services which could displace or offset any aspects of the standby solution, however there was insufficient interest to alter the requirements of the ITT.[12]

Formal tender process

Following internal SHEPD review and market engagement, a procurement strategy was agreed to allow for the most effective method of procurement for delivery of the project's requirements. The process was designed to be as open as possible to encourage smart, flexible, innovative and hybrid solutions, hence the intent to procure based on being agnostic to the technology able to be offered to meet the needs of the project. The

12 https://www.ssen.co.uk/ConnectionsInformation/GenerationAndStorage/FlexibleConnections/CurrentCallsForFlexibility/

tender process was based on detailed Employers Requirements highlighting detailed specific functional requirements that the system will need to meet to satisfy the requirements of the project.

A two-stage competitive regulated tender process was undertaken for the Shetland Standby Solution, based on commercial and technical offers. This included:

1) A Pre-Qualification Questionnaire (PQQ) was published via Crown Commercial Services Find a Tender platform. Following completion of this process successful parties were Invited to Tender.

2) ITT Round 1 – six tendering parties were Invited To Tender; during this process engagement was undertaken with all parties to outline requirements and offer clarification where required. Following the receipt of tenders, two parties were selected to progress to round 2.

3) ITT Round 2 – Further information was released to the two tendering parties to inform their technical and commercial proposals. The tenderers undertook design and modelling at this stage to develop their proposals.

4) Preferred Bidder - Following the completion of the technical and commercial evaluation a preferred bidder was selected. This was based on the scoring methodology to ascertain the most economically advantageous tender (based on commercial and technical tender proposals).

Following the selection of the preferred bidder regular meetings have been held. Contract negotiation and other project related matters (connection applications, planning, lease, etc) have been progressed. Additional detail can be found in Appendix C – Procurement & Commercial Strategy.

Technical Feasibility

SHEPD have conducted the required technical assurance to ensure that the third-party solution is robust and has a high likelihood to meet the required specification. Our large capital projects governance framework includes design requirements and a design management plan and also requires additional scrutiny and review by an independent technical party.

During the tender process we issued a detailed functional specification and testing requirements that bidders needed to comply with. The third-party service that has been chosen complies with these requirements. Detailed system modelling has been undertaken by SHEPD, SSEN Transmission and the service provider.

System studies undertaken include:

- Load flow and short-circuit – to confirm suitability of BESS in-feed;
- Protection studies – including island mode and blackstart;
- Dynamic/transient – integration and validation of Standby Service to confirm it achieves D-FRT and island mode stability;
- Voltage step and switching; and
- New connections (e.g. protection, earthing, harmonics, P28 study)

SHEPD also commissioned a third party to produce a report analysing the effect of the disconnection of the HVDC link on the Shetland Distribution system. Due to the Transmission connected generation on Shetland the sudden disconnection of the HVDC link will produce a temporary transient overvoltage which will be reflected through the distribution network. The third-party report concluded that that for any voltage level this overvoltage waveshape is acceptable.

The system studies will be supplemented by defined functional testing at the National HVDC Centre to test the whole system solution including the D-FRT capabilities of the Standby Service. It is proposed to recreate, as much as practically possible, the worst-case network conditions such that the response of the Standby Service can be monitored and compared against the modelled results.

8. LONG TERM STRATEGY FOR SHETLAND

Working with SSEN Transmission, we have considered the longer-term security of supply pathways for Shetland out to 2050 and beyond. Group Demand on Shetland is currently 44MW and there is no interruption to the entire Group Demand for a First Circuit Outage (FCO) as it is secured immediately by generation at LPS, supported by SVT and DG. By 2050 forecast Group Demand on Shetland will be 94MW meaning the entire Group Demand will need to be secured immediately for a FCO and in addition the majority of the demand will need to be secured for Second Circuit Outages (SCO). This means that by 2050 we will need at least two and possibly three routes of supply for Shetland. The pathways to provide these routes are as follows (and summarised in Figure 1.)

Pathway 1: A single Transmission link supported by Battery and fault ride through solution. The battery and fault ride through are required in the event of fault on the Transmission link to keep the lights on until Lerwick Power Station can get up to full capacity. We would need to seek a new service or battery at the end of the asset life (10-15years) and also invest in LPS to ensure that it is capable of running beyond the mid-2030s while also meeting environmental legislation.

Pathway 2: This starts with the same solution as in Pathway 1 but sees a second Transmission link installed in the mid-2030s. Given lead times this is realistically the earliest point at which a second link could be operational. The second link would likely be in place of any investment in new battery asset or service at the end of the current service contract and would also likely reduce the investment required at LPS as less back-up capacity would be required.

Pathway 3: This is the same as Pathway 2 but sees a third Transmission link installed in the 2040s. There are currently no grounds for a needs case for a 3rd link based on known developments around offshore wind and demand. However, it is a possible pathway depending on future developments. A third link would remove the need for any reinvestment in LPS or need to replace the battery service/rely on flexibility services.

Figure 1 below provides a summary of the pathways and key decision points.

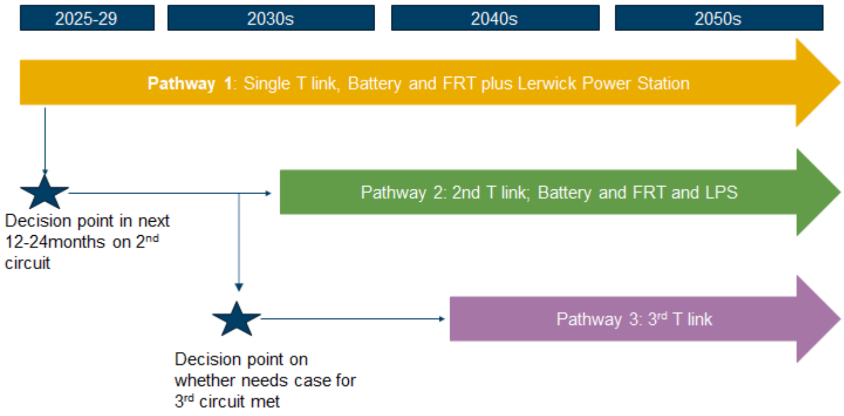

Figure 1 - Shetland Pathways and Key Decisions

Our current engagement with SSEN Transmission and wider stakeholders indicates that Pathway 2 looks the most credible. This is due to:

- Three wind farms totalling 240MW gaining consents (two of which with CfDs);
- [redacted] of hydrogen electrolysis demand expected by 2028;
- Further Transmission demand applications of [redacted] with the potential for more to be identified through stakeholder engagement;
- The requirement to reduce carbon emissions from Oil and Gas by 50% is driving the need for industry to electrify assets. We have already seen this via [redacted] and SSEN Transmission's engagement with the [redacted] has identified approximately [redacted] of further O&G platform electrification demand to the southeast of Shetland; and
- [redacted] If a second link does go ahead, it will provide additional flexible resources which may help to manage future demand and generation without the need for a 3rd Transmission link. However, in the context of the funding case for the Shetland Standby Solution the key point is that all three pathways require a battery and fault ride through service for at least the lifetime of those assets (10-15years). Consequently, it is a no regret investment as part of the longer-term strategy for Shetland. The long-term CBA illustrates comparative costs for each of the pathways based on indicative costs information available.

There will be some key decision points on the evolution of the whole system solution, with the next being whether a needs case for a second link has been meet. This will help influence decisions over the investment required at Lerwick Power Station and also the level of capacity and frequency required from a standby service. We will be continuing the joint planning with SSEN Transmission, ESO and wider stakeholders to ensure a joined-up approach to all investments on Shetland.

Further detail on our long-term strategy for Shetland can be found in Attachment 2 – Shetland Long Term Strategy Paper.

9. CHANGES SINCE DRAFT SUBMISSION TO OFGEM

Since we submitted our draft re-opener application to Ofgem in July 2023, we have progressed negotiations with the third-party service provider which resulted in some changes to the commercial provisions of their service proposals. We provided an update to Ofgem on these issues in December 2023, see Attachment 6. The options considered in the CBA have been updated to reflect the below changes and still demonstrate that proceeding with Option 2 with the service provider is the most cost-effective solution for GB consumers.

Project Finance and Commercial Risk

[redacted]

[redacted]

Increase in Prices

In the time that has passed between the service provider placing its bid (January 2023) and the final negotiations taking place (December 2023), the service provider has advised that the annual service costs need to increase from [redacted] per annum (its original bid) to [redacted] per annum as a result of increases to the costs of plant and material, operational and maintenance costs, insurance, grid restraints and interest rates. We have updated the CBA to reflect these price increases and this continues to demonstrate that proceeding with the Service Provider (Option 2) is the most cost effective solution for GB consumers.

Transmission Connection

We have been advised by SSEN Transmission that the sequencing of energisation date for the standby solution will now be November 2025. This will mean that LPS will be required to run in full duty for longer than originally expected, which will result in the additional costs of running the station requiring to be recovered via the existing UM. These costs are not included in this application, which relates to costs associated with the Shetland Enduring Solution (SESt) only. These costs will be captured under the Shetland Extension Fixed Energy Costs Re-opener mechanism under Special Licence Condition 3.2 Part Q. Again, factoring this delay into the CBA did not change the outcome of Option 2 being the preferred approach.

10. ONGOING UNCERTAINTY

The cost uncertainty has reduced with the conclusion of the tender process for the standby solution service however, a level of uncertainty still remains on a number of aspects of the project. This includes but is not limited to: the timing of the connection to the Transmission system; the number and duration of outages on the HVDC link; significant changes in demand levels or large new connections; the magnitude of revenue trading for the service provider; finalising contract clauses for the service provision; and the final transmission connection agreement for the connection and associated use of system charging for the standby service. There is an additional re-opener application window in 2028 which we would utilise to apply for changes to allowances should any of these scenarios out with our control result in material changes to the costs we incur (upwards or downwards).

Timing of Transmission Connection

The sequencing of the connection to the Transmission system will result in running LPS for longer than intended. As explained in the Transmission Connection section above, this may result in additional capital and operational costs at LPS and will result in additional fuel costs. Any additional capital or operational costs for running LPS will be captured under the designated re-opener mechanism for Shetland Extension Fixed Energy Costs under Special Licence Condition 3.2 Part Q. The re-opener window for this is January 2028. Additional fuel and environmental costs for running LPS for longer will be treated as pass-through under Special Licence Condition 6.1 Part C Shetland Variable Energy Costs. These costs therefore do not form part of this submission. Any further delays beyond November 2025 will result in further additional costs at LPS.

Number and duration of Transmission Outages

The estimated cost of the standby solution is based on the expected HVDC link availability as provided by SSEN Transmission as [redacted] If there are more frequent outages on the Transmission network or if any are longer than expected in duration, then there may be increased charges from the service provider to cover additional costs, not included in the contract. There is a re-opener application window under Special Licence Condition 3.2 Part P, which will be triggered if costs increase (or decrease) beyond the materiality threshold. In addition, an increase in the number and duration of Transmission outages would also increase the running time at LPS which would also increase fuel costs. As detailed above, these would be treated as pass through.

11. VALIDATE INVESTMENT PLANS AND BENEFITS WITH STAKEHOLDERS

This section of the reopener submission describes the stakeholder engagement strategy that was implemented to inform our proposed investment for the Standby Solution for Shetland. This includes the engagement activities that have been undertaken, the stakeholder groups that have been approached, and the feedback that has been gathered from this stakeholder engagement. It should be noted that the additional costs of supplying electricity to Shetland are covered by all GB consumers as part of the Hydro Benefit Assistance Scheme.

Our RIIO ED2 Stakeholder Engagement Strategy

Stakeholder engagement was a critical part of the preparation of our ED2 business plan. An engagement plan was implemented to gather feedback from a diverse range of stakeholders.

A key activity which provided feedback relevant to our Shetland enduring solution ED2 plans was a Shetland stakeholder event focusing on our standby approach and the further engagement we undertook as part of our ED2 business plan[13].

The virtual stakeholder and consumer engagement event was held on 9 December 2020 with a range of stakeholders including representatives from Scottish Government, Shetland Islands Council, local developers, and other large demand customers.

A significant amount of stakeholder engagement was also undertaken on the link contribution proposals, now approved, in the form of many bilateral meetings with local councils, the Scottish Government and island stakeholders, published materials, the CUSC modification process, and through Ofgem's own consultation on the approach.

Stakeholder Engagement to Date

SEPA

Engagement was undertaken with SEPA to confirm the need for standby generation, and to identify SEPA's views on the application of relevant environmental legislation. Engagement continues as required to ensure compliance.

Shetland Demand and Distributed Generation Customers

SHEPD Connections regularly engage with key demand and distributed generation customers in Shetland. This ensures the network design, infrastructure requirements and forecasts of demand and generation remain accurate.

There is a large new demand connection progressing with a connection to the Shetland Distribution system. At present there is no need to augment the D-FRT and blackout avoidance service, however demand growth will be monitored over the coming years and the re-opener at the end of RIIO-ED2 will be used to increase the

13 https://ssenfuture.co.uk/wp-content/uploads/2021/12/A_8.1_ScottishIslands_CLEANFINAL_REDACTED.pdf

capacity if required. The project team worked directly with the customer to detail the benefits of the solution and a visit was hosted in November 2023 to demonstrate the progress which had been made at site.

Targeted engagement will also be required with specific customers to communicate specific new aspects associated with the connection to the Transmission system, including day-to-day operational arrangements and outage procedures, and any changes to the rules of the ANM scheme.

Shetland Islands Council

SHEPD have worked closely with the local authority's development services and infrastructure services directorates. This included the approval and discharging of conditions associated with planning applications for the Gremista GSP and Standby civil platforms and supporting the preferred bidder with their consultation of a section 36 Energy Consents Unit application. The council offered no objections to the application in December 2023.

We engaged with their Future Energy team on their plans for the islands alongside oil and gas majors under the Orion Clear Energy Project[14], the primary focus of which is the decarbonisation of oil and gas activities. The Project envisages other workstreams including the development of a hydrogen economy on Shetland, which may be relevant to future standby discussions. Further engagement has continued with the local authority to share the standby proposals, to identify near and medium-term energy requirements, to discuss how the standby and wider energy arrangements play a role in the islands' Net Zero strategy, and any collaboration that can be taken forward, including in relation to potential future standby solutions.

A presentation to the full council on the whole system solution for Shetland was given in January 2024.

SSEN Transmission

Engagement with SSEN Transmission has been ongoing since our work to develop the contribution proposals and has become regular following application to connect to the Transmission system. Development of the operational philosophies and technical specifications relevant to the Distribution-Transmission connection and operation of the respective networks on Shetland are progressing.

We are also working with SSEN Transmission to develop the GSP in accordance with our connection agreement and to analyse the technical characteristics presented by the future Shetland network arrangement driven by the T-D interactions. In particular, the impact of transmission-connected windfarms on our distribution network and the single link connection to the GB system. Detailed studies of voltage and frequency during the first 100ms following the trip of the HVDC Link have been carried out to confirm D-FRT can be achieved along with a third-party review of the waveforms against appropriate standards and designs. Further details can be found in Appendix B. Project director calls and working level meetings for various disciplines take place weekly to fortnightly at present as the projects have moved from development into execution.

We are also working closely with SSEN Transmission on the development of the longer term (beyond 10 years) strategy for Shetland. Further detail on this is included in Section 8 and Attachment 2.

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14 Orion Clean Energy Project | Providing clean affordable sustainable energy for our future

Ofgem

There has been extensive engagement with Ofgem over the past 13 years in relation to the enduring solution for Shetland. A summary of the history of policy decisions for Shetland is included in Attachment 4 – Shetland History of Policy Decisions.

Most recently, over the course of 2022 and 2023, multiple bilateral meetings have been held with Ofgem to provide updates on our progress with the tender process and outcome, as well as on our plan for the re-opener submission. In May 2023 we submitted an initial draft of this re-opener submission to Ofgem for review and feedback. Following this and weekly bilateral meetings to discuss Ofgem's feedback, we provided a second draft in July 2023. Ofgem agreed to carry out this review of a draft submission due to the requirement for us to progress with the service provider prior to the formal re-opener window of 24th-31st January 2024. In a letter of September 2023, Ofgem agreed with our recommended approach and highlighted areas that should be included in our formal re-opener submission, which included more information on the long-term strategy for Shetland and further detail on the trading aspect.

In December 2023 we provided Ofgem with an update on changes that had occurred since the draft submission, which included [redacted], an increase in costs from the service provider and a delay to the transmission connection. We confirmed to Ofgem that having updated the CBA accordingly, Option 2 remained the recommended approach.

Stakeholder Engagement Feedback

The following questions relevant to our future management of the Shetland network were put to our stakeholders at a Shetland standby event in December 2020. Below each question is a summary of the key feedback that was gathered from the stakeholder engagement exercises that are described above.

We invited feedback on questions around whether to prioritise maintaining the current level of security of supply for the islands, the ability of renewable generation to provide power during outages, and whether to utilise existing generation or procure, build and use new standby solution, reflecting on the potential impact on the cost on these decisions.

Stakeholders expressed unanimous support (100%) for maintaining the existing level of security of supply, very strong support for accommodating renewables during outages (89%), and strong support for utilising existing assets (69%).

Table 7: Stakeholder responses, Shetland standby event – December 2020

Poll Question	Poll Option	Count	Total Votes	Results
Do you agree with our proposed principles?	Yes	19	20	95%
	No	1	20	5%
Could you give us a bit more information about why you chose your answer	Agree overall. Especially happy with the fact that renewables will be utilised as a backup option. Maybe hydrogen can be part of the backup option as well	1	7	
	The top priority dominates correctly. The further objectives are comparatively more equal.	1	7	
	Agree with the broad principles. More detail on how fossil fuel-based backup solutions would be assessed particularly accounting for emissions and cost of carbon	1	7	
	Clearly vital to have a 2024 capable solution for the short and medium term. Much more questions about long term	1	7	
	Resilience of the system following the loss of the connection to the mainland has been considered.	1	7	
	Enable development wider renewables opportunities	1	7	
	Resilience Hydrogen Innovative	1	7	
For Shetland's Future Standby solution, please select the one that best represents your views:	SSEN should prioritise maintaining the current security of supply for the islands at a slightly higher cost	17	17	100%
	SSEN should prioritise a slightly lower cost solution which would result in short duration (around 1 hr) occasional loss of supply	0	17	0%
For Shetland's Future Standby Solution, please select the one that best represents your views	Prioritise the ability of renewable generation to provide power during outages, at a slightly higher cost	17	19	89%
	Constrain renewable generation from providing power during outages, at slightly lower cost	2	19	11%
For Shetland's Future Standby Solution, please select the one that best represents your views	Utilise existing generation until 2030s at lower cost, then seek Net Zero options from the market?	11	16	69%
	Procure, build and use new standby solution until 2030s-40s at higher cost, then seek Net Zero options	5	16	31%

Further Stakeholder Engagement was carried out for our proposals for Shetland as part of our RIIO ED2 Business Plan. The following is a summary of the engagement and results.

ENGAGEMENT SYNTHESIS

Stakeholder engagement	
Engagement details	**Insights derived**
Non-consumer stakeholders We tested our **Scottish Islands strategy, outputs and costs** with a broad range of non-consumer stakeholders to understand their views on the **acceptability and bill impacts** of our Draft Business Plan via an online consultation event and surveys	• A consumer group stakeholder questioned why there was no mention of smaller producers that are already generating electricity on Shetland and feeding into the local network. [E151] • A vulnerable customer representative questioned the use of fault ride-through on the Shetland network as part of the investment, why it was utilised in that context and whether it would also be implemented elsewhere. [E151] • A national government representative thought that the Shetlands is a really good example of whole systems and the outcome for the Shetlands was pretty unique, perhaps driven by need rather than being whole systems from the outset. They thought it would be helpful to understand how that's been taken and incorporated into what we are doing and what is meant by whole systems as part of that strategy. [E151]

Business representatives We co-created our ED2 strategy for planning reliable electricity supply for consumers in the Shetland Islands by seeking their input on the Shetland standby reliability arrangements and transition to net zero at an online workshop	• Building trust and communicating honestly with stakeholders in Shetland when things go wrong is extremely important; issues in the past with the Viking energy project mean stakeholders are sensitive [E072].
Local Authority, distributed generation customers, community energy schemes, contractors, consultants We co-created a solution via a bilateral meeting with Shetland Islands Council and an Open Forum with multiple stakeholders focused on standby arrangements for Shetland and gather additional feedback on Shetland-specific elements of our Whole System Planning and Reliability strategy	• Stakeholders were unanimous that the future standby solution should maintain the current security of supply for the islands at a slightly higher cost rather than adopt a slightly lower cost solution which would result in short duration (around 1hr) occasional loss of supply [E067] • 89% of stakeholders at the event said we should prioritise the ability of renewable generation to provide power during outages, at a slightly higher cost, over constraining renewable generation from providing power during outages, at a slightly lower cost. [E067] • 69% of respondents said that we should continue to use existing generation until 2030s at lower cost, rather than procure, build and use new standby solution until 2030s-2040s at a higher cost and then seek net zero options [E067] • A local authority was glad to see that the resilience of the system following the loss of the connection to the mainland has been considered [E067] • Renewables – possibly including hydrogen – should be incorporated in the backup option [E067].

Engagement statistics

ED2 ENGAGEMENT EVENTS	INSIGHTS	STAKEHOLDERS ENGAGED
10	53	298

Stakeholder segments engaged

CONSUMERS	Domestic customers	Customers in vulnerable situations	Transient customers	Next generation bill payers	SMEs	Major energy users	
CUSTOMERS	Distributed generation customers	Builders and developers	Community energy schemes	Landowners/ farmers			
POLICY MAKERS AND INFLUENCERS	Government	Research bodies, policy forums and think tanks	Media	Consumer groups	Regulators		
COMMUNITIES AND LOCAL DECISION MAKERS	Local authorities	Charities	Academic institutions	Housing associations			
	Vulnerable customer representatives	LEPs	Emergency response	Healthcare	Community interest bodies		
WIDER INDUSTRY AND VALUE CHAIN	DNOs	Transmission	GDNs	Water	Telecoms	IDNOs	
	ICPs	Consultants	Energy suppliers	EV charging	Other supply chain	Storage and renewable providers/ installers	Transport and highways agencies
PARTNERS AND ENABLERS	Current and future employees	Contractors	Service partners	Shareholders	Investors	Business advisers	Trade Unions

EVIDENCE ASSESSMENT

Engagement scoring key

The engagement score assigns a weight to each source accounting for the robustness of the engagement event and the relevance of the feedback to the topic.

Score	Description
1-1.66	Limited evidence of good event planning, methodology or data collection. Feedback provided is high level with tangential relevance to the topic.
1.67-2.33	Good evidence of engagement planning and discussion of data collection methods, but limited depth of feedback and range of opinions. Feedback not necessarily fully aligned to the topic and only provides a limited insight and thus moderately useful.
2.34-3	Well conducted, trustworthy event with highly relevant feedback. Specific, clear and relevant information with clear link to the topic discussed and high value added.

Phase	Date	Event ID	Event name	Key stakeholder groups	Number of stakeholders engaged	Engagement score
Phase 4: Testing and Acceptance	Oct-21	E153	Employee Consultation Document Engagement on Draft Plan	Current and future employees	3	1.8
	Sep-21	E151	Consolidated Outputs and Costings Event	Contractors, Consultants, Local Authorities, National Government, Storage and Renewables suppliers, Supply Chain	106	2.5
	Aug-21	E174	Consumer and Vulnerability Employee Engagement	Current and future employees	17	1.5
	Jul-21	E149	Citizens' Jury	Domestic Customers	34	2.0
	Jul-21	E167	Sustainability Strategy consultation	Vulnerable customer representative, A storage and renewables representative and Community Interest Group	4	1.5
Phase 2: Co-creation	Mar-21	E086	Powering Scotland's Isles bilaterals	Local authorities	7	2.0
	Feb-21	E095	Remote Island Communities workshop - Orkney	Local authorities, distributed generation customers, community energy schemes	18	2.0
	Jan-21	E070	Marine Scotland bilaterals	National government	2	2.5
	Dec-20	E067	Shetland Engagement Forum	Local authorities, distributed generation customers	23	2.5
	Sep-20	E072	Annual Stakeholder Workshops - North	Local authorities, vulnerable customer representatives, housing associations	84	2.5

12. PROJECT DELIVERABILITY AND MONITORING

Project and Governance Structure

Within SHEPD, the Shetland Enduring Solution project has triggered the SSE Group's Large Capital Delivery Governance Framework due to the expenditure levels and unique nature of the project.
The purpose of the framework is to ensure that all large investment projects are governed, developed, approved and executed in a safe, consistent, sustainable and effective manner. Our goal is the safe and timely execution of our project to deliver value in line with our RIIO-ED2 business plan.

The governance process prescribes the required deliverables that must be produced and approved to allow the project to progress through the lifecycle of the project with Gates at each key point. This establishes an effective line of sight and assurance that at each Gate (key decision point in the lifecycle) everything is in place to allow the necessary Committee or Board (based on financial level or complexity) responsible to approve progression through to the next Gate. This also includes an independent review of the project (project assurance review) prior to each Gate giving a recommendation and any suggested remedial actions.

The key gates involved are listed in Figure 1 below.

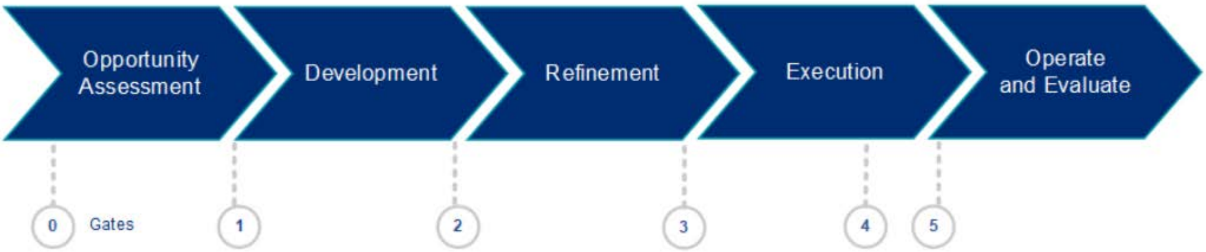

Figure 2: Key gates in LCP governance process

For the Shetland Project the LCP manual mandates that a Project Review Board be formed, and key project resources are appointed, including a Project Sponsor, Project Director and Project Manager. We have had a PRB in place since the commencement of the project with the relevant resources appointed.

The project review board is held monthly, chaired by the project sponsor and attended by key Directors of the Distribution Executive Committee, including the Managing Director of SSEN Distribution.

The project team is a multidisciplinary team made up of technical, procurement, regulatory, legal & commercial, risk management, health, safety & environmental, quality and communication professionals supported by specialist consultants.

Monthly key performance indicators are provided to the Large Capital Projects Committee to monitor progress between Gates (and the associated reviews).

Deliverability of the recommended solution

The delivery model is based on the standby solution being designed, delivered and operated by a third-party service provider.

We have provided a detailed functional specification which the service provider must meet. They have provided their design which has been reviewed by our technical teams with support from specialist consultants to confirm it achieves the specification. The third-party service provider is contractually obligated to provide the service and availability payments are paid in arrears rather than upfront, meaning that an issue in terms of meeting the project milestones could ultimately result in non-payment to the service provider. The above LCP process ensures that we closely monitor milestones to mitigate the risk of this occurring.

There are a number of other remedies specified under the contract in addition to non-payment, these include requiring a recovery plan from the service provider and if it was a technical issue, we would require alternative solutions to be provided by a certain date. Were a more significant issue to be encountered in the run up to go live, the ultimate step would be to terminate the contract. Further details on the steps to termination of the contract are provided in Section 9 and Appendix E.

Resourcing

A full resourcing plan was provided as part of the service provider's bid. Having reviewed this in detail and discussed resourcing with the service provider, we consider that the resourcing proposals are appropriate to ensure timely delivery of the project. Under the contract, they are obligated to engage an adequate number of competent and suitably qualified and experienced personnel to ensure appropriate performance of the services. An updated resourcing plan will be provided once the final contract is in place to ensure that they can demonstrate that sufficient resources will be available to deliver the project plan and meet the milestones. We then have the requirement to review and approve this. Should we consider this not to be sufficient at this stage we would engage further with the service provider, ultimately should resourcing become an issue, this could result in non-payment to the service provider.

Key Performance Indicators

The service provider is contractually obliged to provide monthly management reports on the key performance indicators in advance of the service being provided. This includes providing updated plans and documentation on key aspects of the project such as: project management; engineering; IT; environmental and sustainability; safety; and commercial aspects.

Once the service is energised and live there will be close monitoring to ensure that the required service is provided in the event of an unplanned outage.

Detailed Project Schedule

Activity milestones for project delivery, personnel on boarding and training are provided in Table 8 below.

Table 8: Key delivery milestones

Gate	Gate Description	Status
0	Opportunity Assessment	Complete
1	Development	Complete
2	Refinement	Complete
3	Execution	21st May 2024
4	Commissioning	2nd April 2025
5	Operate & evaluate	29th May 2026

13. CONCLUSION

We are formally seeking approval from Ofgem under Special Licence Condition 3.2 Part P for Shetland Enduring Solution costs of £27.13m in ED2 to progress the standby solution being procured as a service under Option 2. Due to the uncertainty associated with the trading/benefit stacking it is recommended that costs are currently assumed for the full service price excluding trading/benefit stacking.

We have set out the options considered and our recommended approach for the Shetland Standby Solution, alongside details of the costs and benefits with each to demonstrate that the recommended approach is the most cost effective for GB consumers.

As detailed above, we have considered the following options in our assessment:

- Option 1: Asset purchase of Standby Solution. Delivery in 2025/26.
- Option 1b: Asset purchase of Standby Solution. Delivery in 2026/27.
- **Option 2: Standby Solution procured as a Service – without Trading.**
- Option 2b: Standby Solution procured as a Service – with Trading.

Table 9 below sets out the costs that we expect to incur in each year of ED2:

Table 9 - Summary of Shetland RIIO ED2 BPDT costs

Cost category	Unit	2023/24	2024/25	2025/26	2026/27	2027/28	Total
Shetland Enduring Solution costs (SESt)	£m	4.19	0.84	4.65	8.72	8.72	27.13
Note: The above table covers the SESt RIIO-ED2 costs only. As the proposed service will run for a 10-year period, approval of this UM funding will commit us and consumers to the full 10-year contract. As such, the full-service period costs are included in the CBA (£92.55m total). These costs will be included in our baseline costs for RIIO-ED3 and RIIO-ED4 accordingly.							

Option 2 is recommended because it is the most efficient compliant solution to secure the Shetland demand, whilst also providing the opportunity for future price reductions as a result of the battery being traded by the service provider. In addition, it preserves future flexibility to transition to a lower carbon standby solution when one becomes available. The chosen option is modular in nature and can be augmented to meet future new connections and the changing future demand and generation requirements for Shetland.

Due to the uncertainty regarding the possible revenues which could be made from trading/benefit stacking, it is proposed that the contract will be placed based on the maximum amount and that a benefits sharing element is put in place with the service provider such that they will be incentivised to trade/benefit stack to reduce the cost of the standby service to our customers.

We currently do not have any allowances within RIIO-ED2 regarding the Shetland Enduring Solution because at the time of the RIIO-ED2 business plan submission we were still undertaking the procurement process and hence there was a high level of uncertainty on the costs. This re-opener application under Special Licence Condition 3.2 Part P in January 2024 is for the costs of the Shetland Enduring Solution in RIIO-ED2: £27.13m. These are in excess of the Materiality Threshold set out in the licence condition of £2.16m. It should also be noted that there will be ongoing uncertainty in relation to these costs, as aspects such as the timing of the transmission link, and changes to the expected demand on the island could have an impact on costs. There is a second re-opener window available under the licence condition at the end of RIIO-ED2, which we would utilise in this event.

APPENDIX A – BACKGROUND & ANALYSIS

Shetland is an archipelago in the North Sea located 170km north of mainland Scotland and is part of our licence area. It is presently not connected to the Great Britain (GB) transmission network therefore we act as the Distribution System Operator on the island, balancing supply and demand while operating the synchronous generation owned by SSE Generation at LPS (installed capacity of 70.75 MW). This is supported by a power purchase agreement in place with privately owned third-party generation at SVT. SVT expect to cease operation of their power station in 2025 in line with environmental legislation[15] and have applied for a demand connection from SHEPD. Distributed Generation (12.3MW of onshore wind and tidal) make up the remainder of the generation mix managed by an Active Network Management (ANM) scheme.

It was recognised in 2010/11 that an enduring security of supply solution for Shetland should be sought, and a new obligation was placed in our licence, CRC 2Q, to require us to bring forward an integrated plan to manage supply and demand. We have made three enduring solution recommendations in response to the obligation: the original Integrated Plan (IP) in 2013, the New Energy Solution (NES) recommendation in 2017, and the Whole System contribution recommendation in 2018. The IP and NES recommendations were rejected; however, the Whole System contribution recommendation was approved.

Our 2018 Whole System contribution recommendation set out that we would make a submission for associated standby arrangement allowances following confirmation of the Shetland Transmission link Needs Case. Ofgem approved the Needs Case for the Shetland Transmission link and our contribution towards that link.

We submitted our standby recommendation, 2020-12-23 SHEPD Shetland Standby Recommendation and associated appendices including CBA, to Ofgem in December 2020.

15 Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control). The directive is implemented in Scotland through Part A of the Pollution Prevention and Control (Scotland) Regulations 2012 (PPC 2012). SVT have a derogation from SEPA until 2025.

Existing 33 kV Network Arrangement

We are the Distribution Network Operator (DNO) for the Shetland Islands. The network operates at 33 kV, 11 kV and LV and the existing 33 kV network topology for Shetland is shown in Figure 3 below.

The majority of demand on Shetland is centred near Gremista / LPS and is supplied via the local Gremista Primary substation via three 33/11 kV transformers. There are three 33 kV circuits which supply the rest of the Shetland demand (two running north and one south), combined with interconnection at both 33 kV and 11 kV. Figure 4 shows the Geographic Information System (GIS) snapshots of Gremista substation and LPS.

Shetland presently has an uninterrupted power supply for the first planned or unplanned outage (e.g. outage for maintenance or a network fault). Existing generation at LPS and SVT provides a reliable full duty power supply to Shetland with redundancy to allow necessary maintenance of the engines whilst ensuring security of supply for the unplanned loss of the largest engine. LPS generation is connected at both 33kV and 11kV directly into the Gremista substation and local Primary substation respectively. SVT is connected at 33kV and has a total of four gas turbines with a minimum of two running at any one time. No island-wide blackouts have occurred on Shetland in the past 30 years.

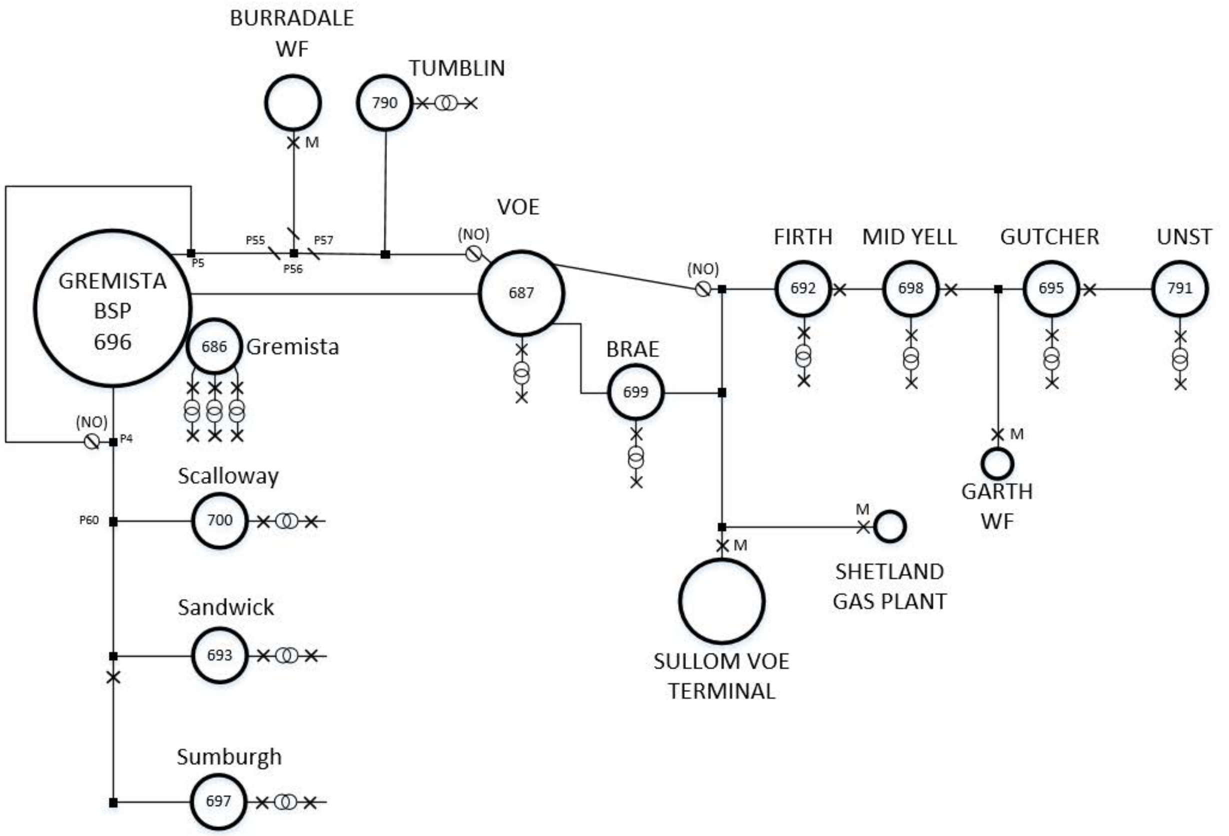

Figure 3: Existing 33 kV network on Shetland

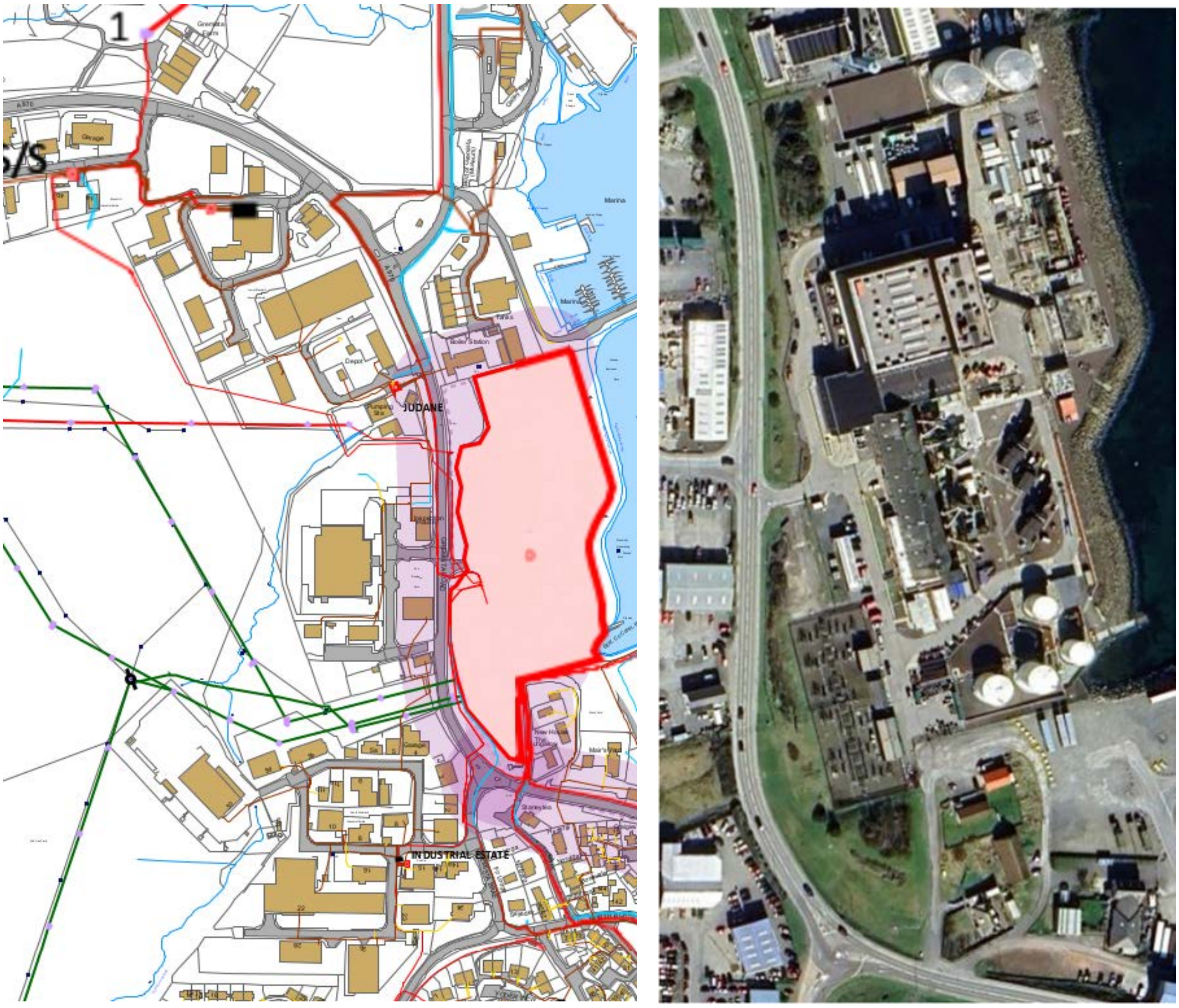

Figure 4: GIS Snapshots of Gremista Substation and Lerwick Power Station on Shetland

Load forecast in RIIO ED2

DFES 2020 demand forecast for Shetland shows that under both the ST and Consumer Transformation (CT) scenarios the maximum demand will increase considerably. The table below shows the extracted demand levels in MW from the DFES demand data for RIIO-ED2 and beyond. Demand levels vary between the two scenarios, increasing from 43.5MW in 2020/21 up to either 58.2 MW or 65.3 MW in RIIO-ED2 (2027/28) and up to either 72.2 MW or 83.5 MW in 2032/33, depending on the DFES scenario.

Table 10: Load Forecast for Shetland

Year	Shetland (DFES ST)			Shetland (DFES CT)		
	Winter (MW)	Summer (MW)	Spring/Autumn (MW)	Winter (MW)	Summer (MW)	Spring/Autumn (MW)
2020/21	43.5	31.7	36.1	43.5	31.7	36.1
2021/22	45.8	34.2	38.4	45.8	34.3	38.5
2022/23	48.0	36.6	40.7	48.4	36.8	41.0
2023/24	50.4	39.1	43.1	51.9	39.7	44.5
2024/25	52.1	40.8	44.8	55.2	42.0	47.7
2025/26	54.1	42.8	46.8	58.7	44.5	51.1
2026/27	56.1	44.8	48.8	61.9	46.9	54.1
2027/28	58.2	46.9	50.9	65.3	49.6	57.4
2028/29	60.4	49.1	53.1	68.6	52.3	60.5
2029/30	63.2	51.7	55.8	72.9	55.6	64.7
2030/31	66.1	54.5	58.7	77.0	58.9	68.6
2031/32	69.2	57.3	61.7	80.2	61.9	71.8
2032/33	72.2	60.0	64.6	83.5	65.0	75.2
Note: This demand table was produced in early 2021 following the release of updated DFES. Previous DFES demand data used for the SHEPD Shetland Standby Recommendation paper issued to Ofgem in December 2020 presented similar values.						

Most of the above increase in demand is associated with non-domestic developments on Shetland. Present new connections activity and stakeholder engagement support this forecast increase in demand.

Existing load factors are quite high for the Shetland total demand, this is a result of the domestic demand being better diversified by the Radio Tele-Switching (RTS) system and the type of commercial/industrial customers supplied having a reasonably constant peak demand throughout the year. This results in the peak spring/autumn and summer demand not reducing as much as usual when compared to the winter peak.

P2/8 Compliance Analysis

Existing Shetland Supply to 33 kV Network

At present there is no interruption of supply to the Shetland islands as a result of a First Circuit Outage (FCO) as defined under P2/8, either as a result of planned or unplanned outages. This is because there is always additional generation running between LPS, SVT and distributed generation (even during peak load and maintenance periods) such that the loss of any one generator, or a circuit/transformer fault, will not result in a blackout for the entire Shetland network.

The existing Group Demand (GD) for Shetland is 43.5 MW which makes it a Class of Supply C as per ER P2/8, over 12 MW and up to 60 MW. This requires that for FCOs a minimum of 29 MW of demand to be met within 15 minutes and the entire GD to be met within 3 hours. There are no Second Circuit Outage (SCO) requirements for a Group C class of supply. Shetland is presently compliant for P2/8 as for an FCO the entire Group Demand is immediately met, due to the modular nature of the generation arrangements, and the absence of a single point of failure. The existing combined network and generation arrangements provide security of supply such that island-wide blackouts have not been experienced in the last 30 years.

Future Shetland Supply to 33 kV Network

Our load estimates and DFES indicate that the GD for Shetland is likely to increase to 60.4 MW and 68.6 MW (DFES ST and CT respectively) by 2028/29 and Shetland will become Class of Supply D for ER P2/8. This will require that for FCOs a minimum of 40.4 MW of demand to be met immediately and the entire GD to be met within 3 hours. For SCOs there is no requirement until GD increases above 100 MW, when it does then it will require, within 3 hours, the smaller of: GD minus 100 MW and 1/3 GD to be supplied; followed by GD within the time to restore the planned outage.

As part of the Shetland HVDC Link project we have applied for a new 132/33 kV GSP (2x 132 kV circuits, 2 x 90 MVA 132/33 kV transformers) to be established at Gremista to supply the Shetland demand. This will provide a single circuit supply as for faults on the single HVDC cable or the converter station the supply will be unavailable. However, it will be available for planned and unplanned outages on any one of the two 132 kV circuits/transformers. The Needs Case for the SSEN Transmission Shetland HVDC Link project has been approved by Ofgem along with our contribution (please refer to the Ofgem's decisions on this and our Shetland Standby Recommendation paper issued to Ofgem in December 2020 for more details).

In order to fulfil the security of supply requirements, as specified in P2/8 and stated above, it is therefore necessary to provide an alternative supply for the Shetland demand in the event of the Shetland HVDC Link or associated transmission network being unavailable.

Limitation with Existing Shetland Network

Once the Shetland HVDC Link is available, the entire Shetland GD will be at single circuit risk for the planned or unplanned outage of the HVDC cable or the associated converter stations. It will not be possible to start conventional standby generation and restore GD within 60 seconds or 15 minutes to meet either of the Group C or D requirements.

It is anticipated that the Shetland HVDC Link and associated transmission system will provide supplies to Shetland for approximately [redacted] of the time over a 20-year period, with the remaining [redacted] accounting for both Scheduled Energy Unavailability (SEU) and Forced Energy Unavailability (FEU). This is based on forced outage and failure rate data from SSEN Transmission for the HVDC system. Over 45 years, availability is anticipated to be around [redacted] The predicted outage regime is included in Table 8 and this has formed part of our functional specification for the standby equipment.

Table 11: Predicted Shetland Transmission outage regime – SSEN Transmission, 2020

Outage regime	Predicted frequency and duration
Planned outages	1% normal year; 2.6% average 45 years c.4 days per year regular scheduled maintenance c.14 days every 7 years – converter station monitoring system upgrade c.3 months every 20 years – converter mid-life upgrade
Forced outages	[redacted] annual Predicted [redacted] individual annual outage events - duration dependent on which part of cable faults, and conditions when fault occurs: • Converter station: [redacted] trips/year; energy unserved [redacted] days per year • Cable: [redacted] trips/year; energy unserved [redacted] days/year Mean Time To Repair: • Land cable 20 days • Subsea cable 65 – 115 days
Overall	[redacted] events / year; [redacted] days average / year; c.[redacted]% unavailability

A forced outage on the HVDC link without any standby equipment would result in a complete outage, causing an island-wide blackout of the supply to Shetland until the fault can be fixed. Evidence from other subsea cable faults confirms it could take several months to repair a fault on the HVDC submarine cable if delays occur due to bad weather and chartering vessels. A target Mean Time to Repair (MTTR) value of 115 days has been applied in modelling of HVDC interconnector availability representing a fault on subsea cabling (around 364km total) where there is restricted access due to weather, which based on SHEPD's own subsea cable experience, we do not consider to be a worst-case view in terms of MTTR; and around 251km of the Shetland HVDC cabling will be subsea. It is therefore essential that an alternative energy source is provided in the form of the Shetland standby solution.

Site Specific Technical Conditions and Operational Arrangements

There is an Active Network Management (ANM) scheme operating on Shetland, implemented under the historical NINES project (Northern Isles New Energy Solutions). It is designed to allow DG to both connect and be managed appropriately to ensure system stability, e.g., if the Shetland demand drops too low then DG is constrained to ensure the synchronous machines can continue to operate and maintain the island frequency, voltage and stability.

The ANM scheme will still be required in some form as part of the enduring arrangements but will require modification to function when the distribution system is supplied from the Shetland HVDC Link, to implement the new standby arrangements, and potentially also further modification if DG secures the ability to export onto the transmission system.

Technical consultants have carried out analysis to determine how to maintain continuous supply to Distribution customers without any blackout being experienced as a result of unplanned outages of the HVDC link or the wider Shetland transmission system. Analysis suggests that equipment will be required to i) enable the Distribution system to ‘ride through’ a transmission fault (‘Distribution Fault Ride-Through’ (D-FRT)), and ii) provide an instantaneous response of energy to meet demand that conventional generation technologies cannot, fulfilling this function while generation plant is started up (‘blackout avoidance’).

D-FRT functionality is expected to be deployed to manage any imbalances or interactions between the transmission and distribution systems immediately upon an outage occurring. In addition to their function of ensuring seamless continuation of supply, the blackout avoidance equipment and services are also expected to enable us to maximise the use of distributed generation *during* outages, and assumptions have been made on the size and cost of this equipment for the purpose of the analysis. The D-FRT response and blackout avoidance system must be capable of absorbing the fault/power transfer from the transmission system to avoid creating issues on the distribution network, including the impact of significant wind generation output, and simultaneously keep the lights on for distribution-connected customers until the core standby solution starts up and takes over. Analysis of the changes in voltage and frequency was completed by third party consultants to determine the impact on existing customers, they determined that no damage to the SHEPD or customer networks was expected.

Further details of the work done can be found in Appendix B.

The specific technical solution, and the associated costs, required for the D-FRT and, similarly, the blackout avoidance scheme are subject to further technical refinement during the ongoing procurement process. These will be determined through engagement with, and analysis by, ourselves and SSEN Transmission, and engagement with the manufacturers/service providers. We are seeking these solutions, services and equipment from the market.

APPENDIX B – LOAD FLOW ANALYSIS

Load flow and contingency simulations were performed for the given Shetland network topology, load demand levels in winter, spring/autumn, and summer, and the corresponding DG dispatches for Shetland in the Power System Simulation for Engineering (PSS/E) models. The load flow results with the updated maximum DFES demand in winter are presented for the CT DFES scenario in 2028/29, as this is the most onerous case in terms of loading conditions on the Shetland network. The load flow results are applicable for all years within the RIIO ED2 period after the HVDC link is programmed to be available.

Thermal Flow Analysis for Shetland Generation at LPS

First Circuit Outage (FCO) Analysis

Table 12: Thermal flow analysis for FCO

Demand Group	Season	Group Class	Contingency	Loaded Circuit / Transformer	MW Flow/MW Rating
Shetland GSP	Winter Max. Load	D	-	LPS Generation	71.60/70.75MW
Shetland GSP	Winter Max. Load	D	Outage on LPS Generator (B Station)	LPS Generation	71.77/58.00MW
Shetland GSP	Summer Max. Load	D	-	LPS Generation	53.96/67.25MW
Shetland GSP	Summer Max. Load	D	Outage on LPS Generator (B Station)	LPS Generation	53.96/54.50MW

For an FCO in winter, the existing LPS generation is overloaded and there is a 1 MW shortfall in generation margin during system intact. When considering spinning reserve for the loss of the largest generator, as shown above this results in a 14 MW shortfall in generation capacity. For the summer peak demand there is sufficient generator margin and spinning reserve, but planned maintenance of LPS generators would need to be considered - see SCO analysis below.

Prior to the HVDC link this shortfall in generation margin and spinning reserve is met by a PPA in place with SVT, which currently operates a minimum of two 18 MW gas turbines at any one time and provides between 4 MW and 15 MW of export to SHEPD.

[redacted] LPS has installed an 8MW/6MWh BESS which provides spinning reserve and peak demand reduction. The proposed options have been evaluated on the basis that they will need to provide for the remaining shortfall in generation margin and spinning reserve once on the HVDC link and the [redacted].

Second Circuit Outage (SCO) Analysis

Table 13: Thermal flow analysis for SCO

Demand Group	Season	Group Class	Contingency 1st Outage	2nd Outage	Loaded Circuit / Transformer	MW Flow/MW Rating
Shetland GSP	Summer Max. Load	D	LPS Generator U8 (3.5 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.96/54.50MW
Shetland GSP	Summer Max. Load	D	LPS Generator U22 (8.1 MW)	LPS Generator U23 (8.1 MW)	LPS Generation	53.98/54.55MW
Shetland GSP	Summer Max. Load	D	LPS Generator U3, U4, U5, U10 or U11 (1 of, 4.5 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.97/53.50MW
Shetland GSP	Summer Max. Load	D	LPS Generator U13 or U14 (1 of, 5 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.97/53.00MW
Shetland GSP	Summer Max. Load	D	LPS Generator U9 (5.8 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	53.98/52.20MW
Shetland GSP	Summer Max. Load	D	LPS Generator U22 or U23 (1 of, 8.1 MW)	LPS Generator U24 (12.75 MW)	LPS Generation	54.00/49.90MW

Summer maximum demand is 16.3 MW lower than the winter peak in 2028/29 for DFES CT. For an SCO it is only possible to switch off the smallest LPS generator (U8, 3.5 MW) and still have sufficient generator margin and spinning reserve. If any of the other LPS generators are taken out of service (e.g. for planned maintenance) then for the loss of the largest LPS generator (U24, 12.75 MW) the remaining LPS generators would be overloaded.

As per the FCO analysis, prior to the HVDC link this shortfall in generation margin and spinning reserve is met by the PPA in place with SVT. This allows for LPS generators to be taken out of service for planned maintenance whilst ensuring sufficient generation for a SCO.

[redacted] LPS has installed an 8MW/6MWh BESS which provides spinning reserve and peak demand reduction; therefore the proposed options have been evaluated on the basis that they will need to provide for the remaining shortfall in generation margin and spinning reserve once on the HVDC link and the [redacted].

Voltage Level Assessment

With the intact network topology and under an FCO, voltage levels are in the limit of ± 6% on 33 kV bus sections at Gremista GSP. This is because the steady state reactive capability of the LPS generation is sufficient to operate and maintain the voltage within the target setting (1.03pu) along with the local 33/11 kV transformers automatic voltage control target settings (1.01pu – 1.03pu). Generation is switched out by LPS during lower demand periods to ensure the machines in service can operate within their limits whilst still maintaining the voltage, frequency and stability for Shetland.

The study results below show that additional Mobile Diesel Generation (MDG), LPS generators or storage / flexible services will be required under higher demand growth DFES scenarios, such as CT. It is possible for the existing LPS generators to provide the steady state reactive power required, but additional reactive power support will be required to provide voltage stability out on the 33kV network during faults.

Table 14: Voltage levels at Gremista GSP

Season	GSP Voltage Set Point	Group Demand	Total Generation	Study Scenario	High/ Low Voltage	Busbar Name
[-]	[p.u.]	[MW]	[MW]	[-]	[p.u.]	[-]
Winter Maximum	1.03	68.6	70.75	Intact Network	1.03/1.03/1.03	LERWCK 3A/3B/3C
Winter Maximum	1.03	68.6	58.00	LPS Generator U24 (12.75 MW)	1.03/1.03/1.03	LERWCK 3A/3B/3C
Summer Maximum	1.03	52.3	67.25	Intact Network	1.03/1.03/1.03	LERWCK 3A/3B/3C
Summer Maximum	1.03	52.3	54.50	LPS Generator U24 (12.75 MW)	1.03/1.03/1.03	LERWCK 3A/3B/3C

APPENDIX C – PROCUREMENT & COMMERCIAL STRATEGY

Shetland Standby – Procurement Process

This paper details the Procurement & Commercial Strategy for the Shetland Standby project. The procurement process has been in progress since February 2022. The second-round evaluation of the tender ended in April 2023, with two proposals received for the project. Following evaluation of the tender proposals, a preferred bidder has been selected.

Commercial Strategy

.The competitive process was designed to be as open as possible to encourage smart, flexible, innovative and hybrid solutions, hence the intent to procure based on being agnostic to the technology able to be offered to meet the needs of the project. The tender process was based on detailed Employers Requirements highlighting detailed specific functional requirements that the system will need to meet to satisfy the requirements of the project.

As part of the commercial tender process, market benchmark testing was carried out by SHEPD to understand the costs associated with the procurement of equipment for the Standby Solution. SHEPD engaged the market to attain costs for the procurement of the relevant equipment and construction of the Standby Solution, SHEPD used these costs for benchmarking against the tender returns. SHEPD have also liaised and continue to do so, with other parts of the SSE Group Business (ensuring business separation provisions are followed) and external market leading consultants to gain information on other similar, Battery Energy Storage (BESS) related projects and trading. External legal consultants ([redacted]) and technical consultants ([redacted]) have been engaged for the project, selected for their expertise in their fields. [redacted] have and are providing guidance on the contractual aspects of the project, whilst [redacted] have provided a report on the trading opportunities the project will have.

Procurement Challenges

The procurement of the Standby Service has been challenging, it is key to highlight that the solution required for Shetland is unlike any other project in the British Isles. Below, highlights some of the reasons for this:

- **Project Requirements:**
  - **Location** – Shetland has various logistical challenges due to its location.
  - **Solution Resilience** – This solution will be the sole remedy for riding through any faults on the transmission HVDC system and maintaining security of supply in Shetland.
- **Uniqueness of Solution / Requirements:**
  - **Fault Ride Through** – Wind Farms – Capturing this Energy to allow the network to 'ride through the fault'.
  - **N-1 Redundancy** – This is not common with a typical BESS project, which are designed to offer power to the grid.
  - Availability requirements.

- **Only Solution** – No other backup for the 45–60-minute period to run up Lerwick Power Station which will then be utilised to provide the required energy to 'keep the lights on' in Shetland.

- **Market Conditions:**
  - **Unprecedented Cost Increases**:
    - Resource constraints increasing labour costs.
    - Ukraine Conflict – impact on global supply chain / price increases / scarcity of materials.
    - Increase in battery operations and operators.
    - Developments in battery technology, meaning battery operators are focussing on larger generation capabilities.
  - **Unprecedented Cost Increases**:
    - Capacity and capability of potential suppliers to undertake due to specialist nature of the works.
    - Lack of other projects on the island of a similar nature – other projects on the mainland more appealing.

Procurement Strategy

The section below, highlights the Procurement Strategy undertaken by SHEPD for the Shetland Standby Solution. It highlights the key activities, completed to date and key activities to be progressed.

- SHEPD require to comply with the Utilities Contract (Scotland) Regulations 2016 as such a regulated tender process for the Standby Solution has been progressed.
- For the Service Contract a Design, Build and Operate, two-stage, one off tender process was undertaken. The tender was based on a set of Employers Requirements. These set out the Standby Solution Projects main requirements, whilst remaining technology agnostic to allow for potential suppliers to propose innovative solutions to meet the predetermined Employers Requirement's. For the second stage of the tender process two tendering parties were selected (based on evaluation of first stage proposals) and further information (modelling data etc) was released to the bidding parties. This allowed for a more focused and refined Technical and Commercial proposals to be submitted by the tendering parties to SHEPD.

Shetland Standby – Round 2 Commercial Proposal Costs

These costs are included in Attachment 1 – Shetland Enduring Solution CBA.

Shetland Standby – Procurement Activities Completed To Date

Table 15 notes the steps that have been undertaken in the Shetland Standby procurement process to date.

Table 15 - Procurement Process

Item	Detail	Date
Pin Notice	PIN notice issued for Ride through solution.	Mar'21
Market Engagement	Market Engagement with four suppliers to help further define the project.	April/May 2021
Procurement Strategy	Following Market engagement and in-house review, consideration of most effective procurement strategy to meet the demands of the project.	Jul'21-Aug'21
Prequalification - Issue	In September 2021 SHEPD published a pre-qualification questionnaire via Crown Commercial Services Find a Tender platform (Publication reference: 2021/S 000-022833). Responses to the PQQ were received in October 2021.	Sep'21-Oct'21
Prequalification - Completion	PQQ evaluation complete with successful selection of six Suppliers that met the requirements of the PQQ, to take to ITT stage.	Feb'22
ITT Process - 2 Stage	A two-stage tender approach was conducted for the ITT. The first stage required the tenderers to produce outline technical and commercial proposals based on Employer's requirements prepared by the Project Team. The tenders submitted were assessed in accordance with derived assessment criteria and models will be used to look at system stability and dynamics to ensure that the overall system is integrated. Tender costs will be assessed against budget and full O&M cost information will be required. For the second stage further information was released by SHEPD to the tenderers. They were required to develop their technical and commercial bids in line with this information. System modelling was undertaken and negotiation/discussion with bidders took place. This element was carefully managed with all parties to ensure comparisons are made on an equal basis.	Note for reference
ITT Release	ITT released to six Suppliers via Jaggaer (SSE Procurement Portal).	Feb'22
Mid-Tender Presentation	A presentation was held via teams by SHEPD to the tenderers outlining requirements of the tender and providing some background to the project.	Mar'22
Clarification Meetings	Technical and commercial meetings were then held with each of the bidders.	May'22
ITT First Round Tender Returns	The first-round tenders were received by SHEPD.	Apr'22
Clarification Meetings	Technical and commercial meetings were then held with each of the bidders.	May-Jun'22
Revised Submissions	Updated Technical & Commercial Submissions from Tenderers following Clarification meetings.	Jul'22

Item	Detail	Date
Release of Second Stage of ITT	Two Bidders were selected for the second stage of the ITT. This was issued in Sept'22. Further information was released to the bidders to inform their technical and commercial proposals. The tenderers undertook design and modelling at this stage to develop their proposals.	Sept'22
Second Stage Tender	Meetings were held to engage with the tenderers regards their technical and commercial proposals.	Sept'22-Jan'23
Preferred Bidder Selected	Following the completion of the technical and commercial evaluation a preferred bidder was selected. This was based on the scoring methodology to ascertain the Most economically Advantageous Tender (based on Commercial and Technical tender proposals). Presentations were then made by the project team to the SHEPD Project Review Board to allow for the selection of preferred bidder to be formalised. Following issue of successful and unsuccessful tender letters, the 'standstill' period began.	Apr'23

Key Activities Remaining in the Procurement Process

Bespoke Contract Negotiation

Contract negotiations have been on-going and are to be concluded with Preferred Bidder. A clear plan has been devised by SHEPD to ensure this process is managed and delivered in a timely manner, whilst safeguarding SHEPD's commercial and legal requirements and drivers for the project.

Planning

A Section 36 planning application was submitted by the Preferred Bidder to the Scottish Government Energy Consents Unit (ECU) and published for consultation in September 2023.

Lease

Option to be agreed and executed between Preferred Bidder [redacted] prior to Contract signature. Negotiation between the parties has begun and is progressing.

Connection Agreements

Revised connection offers expected from SHEPD and NGESO to be issued to Preferred Bidder.

Price Update

A price update has been submitted by the preferred bidder for the Shetland Standby Solution works. The update in price was received by SHEPD in December'23. The annual service costs need to increase from [redacted] (its original bid) [redacted] The increases to the costs has been attributed to plant and materials, operational and maintenance costs, insurance, grid restraints and interest rates This is currently under discussion between the parties.

APPENDIX D – ADDITIONAL OPTIONS REJECTED

Alternative Fault Ride Through

We have considered whether a fault ride-through provided on the transmission network rather than the distribution network would be a more cost-effective solution. There is no reason to suggest that a new procurement process would secure a cheaper alternative to the fault ride-through, if that solution was to be placed on the Transmission network, particularly given the current market conditions. There are also likely to be significant efficiencies in a combined solution of fault ride through and securing the demand, rather than two separate solutions by two different parties. This would be technically feasible but would require a new procurement and planning exercise which would significantly delay implementation of the standby solution. This would mean running LPS in full duty mode for a longer period, at a cost of around £21m a year until the solution was implemented. This option would result in additional costs with no additional benefits. Consequently, we have not taken this option through to the CBA.

Smaller Standby Solution

We have considered whether a smaller standby solution could provide the required security of supply on Shetland at a reduced cost. This option would still require a much larger MW capacity of inverters to achieve the D-FRT (around 100MVA) so any cost reduction would not be linear. In the short term it is possible that, based on the current demand on Shetland, a 40MW battery could provide the capability to ride through a fault on the Transmission system. However, within a few years, our DFES indicates that a 40MW battery would likely not be sufficient to allow all customers to be restored, and we would have to selectively disconnect specific customers to ensure that we were able to meet the requirements of P2/8. A detailed technical assessment would be required to determine if supplies could be restored immediately to meet the requirements of P2/8 or whether there would still be the potential for a blackout given the significant load shedding that would be required.

In the longer term, with a demand forecast of 65.3MW by 2027/28, a 40MW battery would quickly become too small to provide for the fault ride-through and avoid a full blackout on Shetland. The service solution would need to be augmented at additional cost. To knowingly under-size the solution at the outset would be inefficient and result in increased service provider's costs in the longer term, along with reduced opportunity to trade and therefore reduce costs. Importantly, if there is any spare capacity on the battery, the benefits of this will be seen by customers as our costs will reduce due to the increased revenue to the service provider available through trading. Further detail on the trading analysis is provided in the Appendix G and Attachment 5. This option may require Ofgem to grant a derogation from the P2/8 planning standards if this were to cause a blackout. We have not taken this option through to CBA.

Back-up Generation Only

This option looked at providing back up generation such as diesel generators or batteries to individual customers to utilise in the event of an outage. We consider that there are practical, social and environmental issues with this option. Firstly, it won't be practical for some customers. [redacted] They would need to procure a separate battery. Other customers e.g. fish processing plants are likely to be a similar position and even if we looked at funding these batteries, it adds to the complexity of delivery as well as losing economies of scale and benefits of diversity by securing the demand at the Gremista GSP level.

Second, there are social issues with asking customers to have access to these back-up options. Some customers may not want diesel generators constantly on their roads or driveways and the level of customer engagement required to secure understanding of why they are needed and acceptance would be extremely high. Customers look to us (as their network and system operator) to secure these services, not inconvenience them and ask them to back up their own supplies. In addition, it would be entirely unreasonable to expect our customers to start up diesel generators in the event of a fault, which could be overnight in the winter, particularly for the 2000 vulnerable customers on Shetland. This would be a clear backwards step in terms of the supply of electricity to the island.

Finally, there are practical considerations around the ownership and maintenance of the generators, as well as consideration around how customers would be re-energised following a supply interruption once supplies had been restored. Under our electricity distribution licence we are prohibited from owning or operating generation assets. Given that these generators would be static (and not covered by our exemption for mobile generation), this option may require a derogation under standard licence condition 43B.

Whilst we have not costed up this option, a very rough estimate based on previous projects that we are aware of suggests that installing a diesel generator at a domestic house would cost a minimum of £6k. To be provided to every house on Shetland would cost an estimated £84m. Added to the higher costs of providing larger generators (or batteries) for larger commercial customers like Oil and Gas customers (up to 16MW) and fish processing plants, it is very unlikely that this option would be any lower capital cost than the proposed service contract (even without costing the customer engagement required). On the basis of the practical and social issues alone, we have not explored this option further, or costed it in detail for the CBA, as we do not think it is viable. It would likely still require a derogation from the P2/8 planning standards from Ofgem, as it may not secure demand within sufficient time in the event of a loss to the HVDC Transmission link, only providing customers with back up once Shetland blacked out.

Synchronous Condenser and Flywheel

The option of a synchronous condenser and flywheel was initially put forward by bidders in the procurement process, but they did not take this forward to their final bid. The primary function of a synchronous condenser and flywheel is to assist with fault ride through. Without an accompanying solution to secure demand this option would not avoid a blackout of the Shetland Islands whenever there is a full system Transmission outage. Consequently, this option would be higher cost than ‘Do Nothing’ as we would still need to pay for the synchronous condenser and flywheel but it would not prevent a blackout scenario on Shetland in the event of an unplanned fault on the HVDC Transmission cable. Further, this option would require a derogation from the P2/8 planning standards from Ofgem. Consequently, we have not taken this option forward to the CBA.

Medium/High Speed Engines

The option of using medium/high speed engines to reduce the time to get LPS from standby to full operation was considered in our ED2 business plan submission. While it would reduce the time to get LPS from standby to full operation, it would not negate the need to have a separate solution to ride through the fault and secure demand on Shetland. Given that to avoid a blackout scenario it would still require the standby solution, with costs saved on its capacity negated by the additional capex to replace LPS. Therefore, this option is higher cost than ‘Do Nothing’ but with no additional benefit. We have not taken this option through to CBA.

APPENDIX E REDACTED

APPENDIX F – DISTRIBUTION FAULT RIDE THROUGH (D-FRT)

Requirement

For an unplanned outage/fault of the Shetland HVDC Link:

- Ensure that the SHEPD Gremista GSP 33kV network can disconnect from the NGESO/SHET network and ride through the initial transient period (0-100ms) in order to operate in island mode without a blackout occurring to the existing SHEPD network on Shetland.

This is necessary to ensure:

- Compliance with ENA P2/8 Security of Supply Requirement for SHEPD.
  - SHEPD/SHET are unable to restore demand within the required time if a blackout occurs.
- Compliance with SQSS for NGESO/SSEN Transmission
  - SHEPD/SHET are unable to restore demand within the required time if a blackout occurs.
- Ensure no reduction in the security or quality of supply once connected to the HVDC Link.
  - The connection of the Shetland HVDC Link should not de-grade the existing supply.

Background Work

Various studies, technology reviews and market engagements have been done to determine viable options. SHEPD & SSEN Transmission carried out a feasibility study, this included:

- PSCAD studies:
  - Voltage and frequency found to deviate significantly for 100ms when HVDC Link trips.
    - With standby service based on a BESS solution; voltage and frequency improved.
  - Showed a viable solution existed for D-FRT implementation on SHEPD’s 33kV network.
- External review:
  - CESI appointed to review voltage and frequency waveforms against appropriate standards/designs.
  - Determined within limits for insulation withstand, electromagnetic compatibility and ENA ERs.
  - Therefore, no damage to SHEPD or customer network expected.

Future Work

External joint study: SSEN Transmission, SHEPD and Viking Energy Wind Farm to commission PSCAD modelling and study.

- Incorporate all parties’ models.
- Review the prospective operating and fault scenarios to ensure compliance.
- Review the D-FRT functionality with regards to the standby service models from tenderers.

Further testing at the HVDC Test Centre.

- Protection relay operation when supplied by standby service.
- Standby service controller interaction with HVDC converter and transmission connected wind.

Testing Plan.

- Prove D-FRT and island mode functions through studies once final manufacturer models available.
- Lab testing with manufacturer/collaborate with the HVDC Test Centre.
- Tests during commissioning to prove functions with islanded network and once connected.

APPENDIX G – ENERGY TRADING

Energy Trading – Overview

SHEPD's project aim for the Shetland Standby Solution, is for the Battery Energy Storage Solution to be a genuine whole system solution. By achieving this solution, SHEPD highlight below some of benefits which will be achievable:

- The ability for the BESS trade in the GB electricity market
- Added value when the capacity is not being fully utilised in providing essentially security of supply services to SHEPD
- Increasing the commercial viability for a third-party service provider
- Reducing consumer contribution to the BESS
- There is opportunity and risk on the overall magnitude of trading over the service contract term (10 years)

SHEPD propose to share the opportunity and risk for trading with the service provider to reduce costs to consumers whilst incentivising the Service Provider to ascertain the most economic trading position possible.

Energy Trading – Modelling Carried Out by [redacted]

As a form of Market Testing and to further understand the mechanics and process involved in the Trading of Energy, SHEPD engaged the consultancy [redacted], who provided a report detailing the following:

- Power Market Platform models – energy, capacity, balancing and ancillary markets
- Scenarios framed by market experts and market intelligence
- Commodity prices
- Technology
- Demand
- Policy developments
- Battery Market Eligibility:
  - Wholesale
  - Balancing mechanism
  - Capacity Market
  - Frequency response – not eligible due to location of assets
- Shetland specific battery modelling input:
  - Reserve power service and available capacity of the HVDC link determine constraints.
  - Based on contracted T-connected wind (NGESO TEC)
  - Modelled for 1hr, 2hr and 4hr battery
- SHEPD engagement Energy Portfolio Management (EPM) team- SHEPD also engaged with the EPM part of SSE's business, this process was managed via contractual arrangements and processes to ensure business

separation. This allowed for SHEPD to have technical and commercial expertise in the trading market as a resource to aid in analysis and reviews.

This report and engagement with EPM, provided SHEPD with valuable information and guidance which was then used to further discussions with the service providers during the second round of the tender process. It allowed for SHEPD to have up to date Shetland project specific 'benchmark' data to use as a comparator to interrogate the service providers tenders' submissions.

Energy Trading – Assessment of the Opportunity

With the market intelligence SHEPD had derived from the [redacted] report, SHEPD moved to facilitate discussions with the service providers whilst beginning reviews of the trading proposals from the third-party service provider:

- SHEPD engagement with independent third parties who provide these services to the market to assess opportunities
- SHEPD requested that the third-party service providers who are submitting tenders to provide their assessment
- The analysis showed there was a viable trading opportunity that backed up our approach to procure the service via a third-party service provider
- The Trading revenue forecast provided by the Service Providers was compared to the independent analysis SHEPD received via the [redacted] trading report it commissioned. This highlighted that the trading forecasts from the third-party service provider were comparable and in line with the Forecasts provided by [redacted], in that the trading opportunities proposed by the service providers were a valid assessment of the potential trading revenues available.
- SHEPD also noted that if all the risk is put on the service providers, they will cost this risk into their bid and provide little benefit in reduced costs
- It was also noted by SHEPD, that If we share the risk, there is more opportunity to reduce the cost to consumers as we progress through the service term.
- Uncertainty of the Opportunity:
  - Risk – SHEPD note that the Energy Trading market forecast that have been received via the service providers and consultancy report ([redacted]) are a forecast and may flex either positively or negatively, dependent on several variables, some of which are noted below.
  - Key Factors Impacting Trading:
    - Grid connection
    - Transmission connected renewables
    - Demand on the D side
    - ANM Queue
    - Market change

[redacted] Report Energy Trading Forecast - REDACTED

Approach to Trading

The primary function of the standby service is to provide security of supply in the event of an unplanned outage on the Transmission system. When it is not being utilised for this purpose, the battery would be traded in the GB electricity market by the third-party service provider. The following outlines the key details of this approach to trading:

- The service provider would trade usable capacity between demand at any given point and 70MW capacity on the battery;
- Capacity Market would be managed by third party service provider;

- Third party service provider would contract with an independent off-taker who would be responsible to provide route to market services for wholesale and Balancing Mechanism; and
- Third party service provider will also ensure the off-taker is maximising return of the asset.

Expected Markets

It is assumed that wholesale and Balancing Mechanism will be the primary markets for trading the capacity on the battery. This is based on previous experience of the third-party service provider and its external expert consultancy forecasts.

SHEPD commissioned a full report by [redacted] as enclosed in Attachment 5 which demonstrates where the primary trading markets are.

Approach to sharing trading revenue

Our recommended Option 2 is to proceed with funding for the service provider for fault ride-through and blackout avoidance equipment as a service with no trading. The no trading option has been selected because there are multiple factors which will impact the revenue from trading and rather than bake an estimate into the service contract for the standby solution (which would inevitably be conservative), we have reached an agreement with the service provider whereby we log up trading revenues with a percentage of those revenues taken off the costs of the service each year. More detail is provided in this section on this sharing approach will be applied.

For any revenues from the wholesale market and Balancing Mechanism, the following share of net revenue will be applied:

[redacted]

For the Capacity Market, the following share would apply. The reduced share to SHEPD in this scenario is due to the increased requirement for the third-party service provider around pre-qualification, credit cover, testing and reporting:

[redacted]

As outlined in Figure 4 above, the potential revenue stream from the Capacity Market is the lowest of the markets expected to be available and analysed above.

The off-taker share is estimated based on initial engagement and experience from the third-party service provider, but will depend on their forecast and negotiation with them. The third-party service provider would manage negotiation of the commercial agreement with off-taker and also track and review their performance (providing transparency and justification to SHEPD). The remainder will be split on the same proportional basis as above between SHEPD and the third-party service provider.

The above structure represents the current position with our third-party service provider and is included in the contract (subject to final agreement pending a decision on this uncertainty mechanism submission).

Why this approach

The above approach to trading has been selected as it will maximise the incentive to generate revenues using the full capacity of the asset, to reduce the cost to SHEPD and ultimately to consumers overall.
There are a number of factors that make it very difficult to accurately forecast potential revenue from trading the battery, including:

- Uncertainty in revenue forecasts for wholesale, balancing mechanism over duration of contract
- Uncertainty over assets acceptance in the market by National Grid ESO or use in Capacity Market and EMR Delivery Body

For this reason, we consider the sharing approach set out above to be appropriate and fair, ensuring that customers benefit from any reductions in costs to SHEPD as a result of the service provider trading spare capacity on the battery.