PH004240

EJP_SHEPD_INVE_CULL_001-CULLODEN ENGINEERING JUSTIFICATION PAPER

Scottish & Southern Electricity Networks

[redacted]

CONTENTS

1 Executive Summary

1.1 Summary

This paper outlines the need to intervene at Culloden Primary Substation which comprises two 7.5/15MVA CER 33/11kV Transformers and associated 33kV and 11kV switchgear. [redacted]

Within this paper, different options are considered depending on location, electrical and physical solutions [redacted]. To ensure the most efficient and cost-effective solution, an Ofgem-provided CBA is used to determine the option with the best NPV through the whole project life cycle and an Ofgem CEM tool to assess whether employing flexibility would be viable compared to the required MWh exceedances.

Through the whole system approach and overarching stakeholder engagement, the area-specific requirements in terms of flexibility, site requirements and foreseeable local authority plans have been collected to aid the decision-making. [redacted] Whilst including action on HI and CI information does not directly lead to savings in load or non-load investment, it will create efficiencies in outage planning and minimise customer disruption if linked with the reinforcement within this report.

In the Table below the summary of the considered options can be seen.

Option Considered	Description	NPV £m (10 years / whole life)	Year of associated costs	CBA Consideration and Result
1. Do Nothing	Leave existing Transformers in their current state	[redacted]	[redacted]	[redacted] Discarded from options
2. Network Extension	Add one additional Transformer and associated switchgear to increase MVA	[redacted]	[redacted]	[redacted] Discarded from options.
3. Primary Reinforcement	Reinforce Primary Transformers to larger units, also relocate and build new substations due to space constraints.	[redacted]	[redacted]	Progressed to CBA Not preferred option
4. Flexibility solution	Deploy flexibility solutions with either existing demand users or create a market to contract new facilitators for solutions.	[redacted]	[redacted]	Progressed to CBA Not preferred option
5. Combine Flexibility with reinforcement	Deploy flexibility for some years in order to maximise the utilisation of the current assets with minimal flexibility needed and reinforce the Substation once this flexibility requirement is	[redacted]	[redacted]	Progressed to CBA Preferred option.

	not cost-effective anymore.			
6. Transfer load to neighbouring circuits	Transfer load from Culloden Primary to neighbouring circuits with network reconfiguration	[redacted]	[redacted]	[redacted] Discarded from options

From the above-mentioned options only three become physically possible, Option 3, Option 4 and Option 5. The others have either physical or electrical constraints that do not allow delivery or the option does not provide a complete solution to the problems.

Through the CEM and CBA analysis, the preferred option is Option 5, incorporating the available flexibility from 2026 until the end of 2027 when the proposed reinforcement works need to be delivered and energised to ensure the network integrity and that it is safe and efficient to operate.

The proposed scheme delivers approximately 10 MVA additional capacity and it is designed to be sufficient to support the network through its lifetime (taking into account 2035 and 2050 load growth), therefore it will facilitate the efficient, economic, and coordinated development of our Distribution Network for Net Zero.

[redacted]

2 Investment Summary Table

The Table below provides a high-level summary of the key information relevant to this Engineering Justification Paper (EJP) and on the proposed option of reinforcing Culloden Primary transformers and related switchgear. The costs associated with this option have been derived from the ED2 Ofgem Unit Cost Rates, meanwhile, all Net Present Values (NPVs) used to compare the investments were derived using Ofgem CEM and CBA tools. [redacted]

Table 2.1 – Definitions and Abbreviations

Name of Scheme/Programme	Culloden 33/11kV Primary Reinforcement
Primary Investment Driver	Load related – substation thermal overload. Project Number: PH004240
Scheme reference/ mechanism or category	Old: Engineering Justification Paper - CULLODEN v21-03-26 New proposed: EJP_SHEPD_INVE_CULL_001

Output reference/type	2x 33kV Transformer (GM) 7x 33kV CB (Gas Insulated Busbars) (ID) (GM) 12x 6.6/11kV CB (GM) Primary 6.5 km 6.6/11kV UG Cable 1km 33kV UG Cable (Non-Pressurised) 2x 33kV Pole 1x Batteries at 33kV Substations	
Cost – C0(b)	[redacted]	
Delivery Year	2027/2028	
Reporting Table(s)	CV1: Primary Reinforcement	
Outputs in RIIO ED2 Business Plan	Partially funded in RIIO ED2 Plan. Funding covers up to £0.713m as per the previous EJP.	
Spend Apportionment	**ED2**	**ED3+**
	[redacted]	-
MVA released	10MVA (LW) – 11MVA (CT)	-

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4 Introduction

This paper outlines the need for reinforcement of the existing two Continuous Emergency Rated (CER) 15 MVA transformers at the Culloden Primary substation before the end of the RIIO-ED2 price control period due to forecasted demand growth. Culloden is a double 7.5/15 MVA transformer primary substation fed by the Inverness 33kV network and is located in the Highlands and Islands region of the SHEPD licence area.

[redacted] This paper presents options to rectify the projected overload at the Culloden primary substation using flexible solutions and conventional reinforcement. In the Figure below the graphical representation of the SHEPD DFES scenarios can be seen.

[redacted]

In addition to this, due to the aforementioned load growth, related parts of the network will be overloaded as well at both Network Intact and N-1 scenarios as well. On the other hand, these circuits and parts will not be discussed in this paper.

Section 5 of this EJP describes the background of the area and our approach to load forecast, whole system approach and local forecasted flexibility viability. Within this section, the proposed load-related investment plan for the reinforcement of Culloden Primary Substation for the ED2 price control period is detailed as well. The primary driver considered within this paper is load-related, specifically thermal overloading triggered by the demand forecasts. This section of the EJP additionally describes the network studies undertaken, detailing the results which further justify the need for the proposed investment.

Section 6 provides an overview of the considered options and identifies the most appropriate option as a proposed solution to address the network congestion. This section includes a table that summarises the net present value of all the options included in the Cost Benefit Analysis, the year in which each cost is incurred and the year in which each option would need to be triggered. Section 6 therefore summarizes the results detailed in section 7 on the optioneering process and section 8 on the cost-benefit analysis of each option.

Section 7 provides an exhaustive list of the options considered through the option engineering process to establish the most economical and efficient solution. Each option is described in detail, with the EJP setting out the justification for those options which are deemed unviable solutions, and therefore not taken forward to the Cost Benefit Analysis.

Section 8 details the Cost Benefit Analysis (CBA) and provides comparative results of all the options considered within the CBA. It sets out the rationale and justification for the preferred solution. This section also describes how we have established the cost efficiency of the plan with reference to the unit costs that have been chosen.

Section 9 describes the deliverability of the plan for RIIO-ED2 and this proposed investment. It also addresses possible risks based on the required works, the proposed assets, and other surrounding factors, such as the procurement of additional construction space, etc.

Section 10 addresses the strategic aspect of the investments and highlights the long-term aspects of operating a congestion-free grid until at least 2050.

Section 11 concludes the EJP and provides a summary of the main conclusions and recommendations contained within this document. This includes the recommended preferred option, a summary of the costs and timeline of this option, a reasoning on the use of flexibility as well as key risk and delivering options.

5 Background Information

5.1 Existing Network Arrangements

[redacted]

The Primary Substation currently consists of two 7.5/15 MVA transformers with corresponding Circuit Breakers (CBs), one bus section breaker and eight feeder breakers.

The layout for the existing Substation and corresponding assets can be seen below.

Figure 5.1 - Culloden Primary GIS layout

The electrical layout of the 33kV network connecting Culloden Primary and other Primaries to the Inverness Grid is presented below.

[redacted]

The Primary currently has eight 11kV feeders and both 33kV and 11kV electrical arrangements can be seen below.

[redacted]

5.2 Load Forecast for (area of network specified)

Present demand on the Primary can be approximated to be around 6.1MVA for the Summer Maximum and around 9.1 MVA for the Winter Maximum.

The demand projections in MW at Culloden Primary for each DFES scenario are shown in the Table below. [redacted]

The existing 7.5/15 MVA transformers are suitable for winter continuous emergency (CER) operation at 14.55 MVA (at 10°C) as per SSEN policy document TG-NET-SST-026. [redacted]

Currently, there are no large accepted loads or generation scheduled to connect to any of the feeders. For more information see Appendix A.

Looking at the period after ED2 gives an indication of the long-term load forecast. The Figure below shows the load forecast for all four scenarios up until 2051.

[redacted]

The scenarios above give an indication of the necessary headroom to be incorporated into the solution proposal.

5.3 Existing Asset Conditions

This proposal is to overcome thermal overload issues not related to asset condition. [redacted]

[redacted] For more details on the oil report, see Appendix B.

[redacted]

Whilst including action on HI and CI information does not directly lead to savings in load or non-load investment, it will create efficiencies in outage planning and minimise customer disruption if linked with the reinforcement within this report.

5.4 Existing Operational Issues

No known operational issues have been identified.

5.5 Network Analysis Summary

Following the completion of network analysis for the end of the RIIO-ED2 period of 2028, the following constraints/conclusions have been identified:

[redacted]

5.6 Regional Stakeholder Engagement and Whole Systems Analysis Summary

The GSP is not overloaded at present conditions under normal running arrangements or under the N-1 scenario, [redacted]

There are a number of small contracted demand and generation connections totalling about 2.8 MVA and 0.5MW respectively, but for the study purpose, it is assumed these new loads will directly summate onto the 2028 DFES demand.

The currently contracted load and generation to Culloden Primary can be seen in Appendix A.

The contracted load mostly consist of new housing developments and other small-scale loads, with the biggest being 442 kVA. Meanwhile, the contracted generation is mainly small-scale PV and PV&BESS sites, all below 200kW individually.

The available information on planning and development in the region can be seen below.

Net Zero Strategy:

- Targets for 75% emissions reduction by 2030 and 90% emissions reduction by 2040.
- Costed action plan to be published in December 2023.
- Any homes consented from 2024 onward must have net zero-emission heating in place.
- The Council will phase out their fleet's diesel and petrol vehicles by 2030.
- Looking into expanding electric vehicle charge point infrastructure in collaboration with Aberdeen City and Aberdeenshire.
- Developing a business case for replacing diesel ferries with electric vessels.

Highland Local Housing Strategy for 2023-2028:

- Housing Supply Target of 1,840 units per year.
- Aim to deliver 2,918 units of affordable housing between 2022 and 2027 via the Strategic Housing Investment Programme.

Currently delivering the Inverness Zero Carbon Levelling Up Project, which will include £20m of refurbishments and provision of renewable energy at Inverness Castle, along with other forms of regional development.

Also delivering the 10-year City and Region Growth Deal, worth £315m, which aims to achieve economic growth and increased connectivity and digitalisation across the Highlands. Includes the establishment of a North Innovation Hub.

All Scottish councils are mandated by the Scottish Government to produce a Local Heat and Energy Efficiency Strategy by December 2023, so more information on Highland's development plans may come to light then.

5.7 Flexible Market Viability

The estimation of available flexibility in this area is particularly difficult due to the need to make assumptions about domestic and commercial flexibility participation rates and capacity in Scotland. Current flexibility services in rural parts of Scotland have been primarily achieved through hydro and wind, but there is extremely limited generation in the area in question. There is limited data on which to base estimations of domestic and commercial demand side response for such areas. Further complicating this is the existence of a Load Managed Area (LMA), which is expected to reduce the number of available participants until the LMA removal project reaches implementation in this area. More work is needed to understand what the effects of the existing LMA in this area will be on flexibility availability, however, it may be possible for flexibility and the LMA to coexist. If there is time or opportunity, the best way to establish the available flexibility would be to open this area up to the market for procurement of services and undertake close stakeholder engagement so stakeholders understand the potential of delivery in this region. Given that we would be offering connections based on this capacity, we may need to do long-term contracts of firm volume.

Key assumptions used through the flexibility analysis:

- 90% of non-MD customers are domestic, giving an estimate of 5754 domestic households in Culloden and Raigmore.
- 6.6% household participation rates in flex in 2025, up to 8.5% in 2027.

- The average power reduction potential per household is 0.21 kW (based on results from ESO DFS). Growth of EVs and heat pumps has been identified using the DFES data for the CT scenario in each primary, and an assumption is made that 25% of future EV and heat pump connections participate in flex services. Culloden primary S/S is understood to be currently operating in an active LMA. The current DCUSA rules mean that people in an LMA are typically excluded from participation in other flexibility services to ensure the scheduling process overnight is successful. This participation rate would therefore depend on whether the LMA removal project has been implemented successfully in this area ahead of 2025, or another route being found via which an LMA and flexibility services could coexist.
- Assumed 5% of all the MD customer capacity would be available to be turned down for flex (this includes shops, hospitals, schools, etc.) Growth in commercial demand according to the DFES CT scenario has been accounted for in this figure.
- Assumed all of the Allanfearn gas generators in Culloden available for demand turn-up (240 kW).
- Excluded all other generations in the area as there is not likely to be any significant electrical impact on generation under other nearby primaries due to limited interconnection under normal network conditions. There may be scope to investigate further if this could be increased by closing normally open points in the network to facilitate the provision of flex from adjacent assets, however, this is likely to be challenging.
- Assumed all renewable generation or generation for which the type could not be identified does not participate in generation turn-up. Omitted generation under Culloden and Raigmore primaries includes a 165 kW PV generator at Culloden and an unidentified 148 kW generator under Raigmore.

From the assumptions above and through extensive market and area research, the combined maximum capacity for flexibility estimate for Culloden Primary between 2025 and 2027 can be seen in the Table below.

[redacted]

5.8 Confidence Table

Table 5.2 - Confidence Table

Confidence Factor	Certainty (High, Medium, Low)	Comments
Load Forecast	High	Load forecast is in keeping with historical trends and accounts for contracted commercial background. Using LW from DFES highlights stronger growth in the demand on the other hand, CT scenarios are following similar trends on the projections as well.

		All four DFES scenarios are within expectations and should accurately project the area's demand forecast.
Existing Asset Condition	Medium	[redacted]
Existing Operational Issues	Medium	Currently, there are no known operational issues with Culloden Primary. [redacted]
Connections Activity	High	Load forecast is in keeping with historical trends and accounts for contracted commercial background.
Regional Stakeholder engagement	TBC	To update during Design refinement
Flexible market Viability	Medium	
Funding Position	High	The upgrade was proposed to be delivered through ED2 and covered through the previous EJP. [redacted]

6 Summary of options considered

6.1 Summary of Options

Through the early stages of network analysis, stakeholder engagement with corresponding regions, design and delivery, other traditional reinforcement options have been identified as well in addition to the one listed below, on the other hand, either due to location, connectivity, space or associated costs (or more of these above), these options were not even considered in this EJP.

The table below provides a summary of the options considered in this EJP.

Option Considered	Description	NPV – whole life	Year of associated costs	CBA Consideration and Result
1. Do Nothing	Leave existing Transformers in their current state	[redacted]	[redacted]	[redacted] Discarded from options

2. Network Extension	Add one additional Transformer and associated switchgear to increase MVA	[redacted]	[redacted]	[redacted] Discarded from options
3. Primary Reinforcement	Replace Primary Transformers with larger units, also relocate and build new substations due to space constraints.	[redacted]	[redacted]	Progressed to CBA
4. Flexibility solution	Deploy flexibility solutions with either existing demand users or create a market to contract new facilitators for solutions.	[redacted]	[redacted]	Progressed to CBA
5. Combine Flexibility with reinforcement	Deploy flexibility for a number of years in order to maximise the utilisation of the current assets with minimal flexibility needed and reinforce the Substation once this flexibility requirement is not cost-effective anymore.	[redacted]	[redacted]	Progressed to CBA
6. Transfer load to neighbouring circuits	Transfer load from Culloden Primary to neighbouring circuits with network reconfiguration	[redacted]	[redacted]	[redacted] Discarded from options

6.2 Options comparison table

In the Table below, the high-level costs (C0(b)) and related NPV from the CBA can be seen.

Option		C0(b) costs (m)	CBA total results (NPV)				
			10 years	20 years	30 years	45 years	Whole Life NPV
1	Do Nothing	[redacted]					
2	Network Extension						
3	Primary Reinforcement						
4	Flexibility solution						

Option		C0(b) costs (m)	CBA total results (NPV)				
			10 years	20 years	30 years	45 years	Whole Life NPV
5	Combine Flexibility with Reinforcement	£4.072	1.00	1.47	1.81	2.14	2.20
6	Transfer load to neighbouring circuits	N/A	-	-	-	-	-

C0(a) Costs of recommended option as per ED2 submission.

[redacted]

C0(b) Costs for recommended as per ED2 submission adjusted for RPI to 23/24 Price Base

[redacted]

7 Detailed option analysis

7.1 Option 1: Do Nothing

As has been shown in previous sections, the peak load demand at Culloden Primary will increase over the current capacity at both intact and N-1 network conditions by the end of the RIIO-ED2 price control period. This is mostly due to projected load increment driven by generic growth in demand derived from different DFES scenarios, on addition to this, a number of small to medium size demand connections may speed up this process as well.

[redacted]

The existing 7.5/15 MVA transformers are suitable for winter continuous emergency (CER) operation at 14.55 MVA (at 10°C) as per SSEN policy document TG-NET-SST-026. [redacted]

Doing nothing in this case will have multiple implications such as:

- Equipment will be overloaded and therefore its life span will be shorter, especially in case the overall demand is higher than the CER rating of the remaining transformer under a loss of a Primary transformer scenario.
- Compromised network resilience, hence outages may occur more frequently causing economic and reputational loss.
- Security of supply will be endangered.
- New connections will not be able to connect to the grid endangering customer relations and the ability to support economic growth and net zero plans would be impacted.

7.2 Option 2: Network Extension

This option explores the possibility of an additional 33/11kV Transformer, associated switchgear and busbar system to the existing site to increase the available capacity and ensure network integrity under both normal and abnormal operational conditions.

Through site visits, it was proven that installing additional large equipment such as a Primary Transformer within the existing compound would not be possible. The front of the substation partially serves as a public parking which would be difficult to repurpose for construction purposes, also, in doing so, the local community would take the consequences putting SSEN's hard-earned trust into jeopardy. Looking at the back of the substation, starting from the back of the plot, there is a steep incline to about 5 – 6 ft of the land, which would prove extremely costly and difficult to level and make it suitable for construction due to the neighbouring houses and living areas.

From the above, it was concluded expanding the existing substation would be more expensive than purchasing another plot. Hence it was confirmed that the neighbouring areas cannot be used or procured to extend the existing site to accommodate the larger proposed assets.

[redacted] In relation to these concerns, with the above space and site restrictions, the decision has been made that this option is not viable, therefore it has been discarded and not taken forward to any CBA or CEM analysis.

7.3 Option 3: Reinforcement of Existing 33/11kV Primary Transformers

From the Network Analysis summary above it can be seen that one of the options is to replace the existing 7.5/15 MVA CER Primary Transformers to a size that accommodates the demand forecasted until it's end of its lifetime. This is found to be 15/30 MVA considering the current DFES data. This would add 15MVA additional firm capacity to the site, ensuring the double transformers can operate within safe operating temperatures and reduce the risk of failure. This would provide approximately 11 MVA of additional headroom when considering forecasted CT scenarios by the time the end of ED2 and 10MVA additional headroom when considering LW scenarios for the same time period.
The replacement would be considered like a like in terms of the other assets present, with the exception of additional space on each side of both 11kV and 33kV boards to account for future connections and growth.

This option has been captured through an EJP that was submitted for RIIO-ED2 on a high-level basis, on the other hand here will be detailed to reflect current costs and to compare with other options.

Through site visits it was proven that installing larger-size transformers within the existing compound would not be possible, also through the consents team it was confirmed that the neighbouring areas cannot be used or procured to extend the existing site to accommodate the larger proposed assets. Therefore, a new site location is to be proposed for the substation, alongside new 11kV and 33kV indoor circuitry. [redacted]

The new site will require consent and land purchase allocation and to construct a building to house the 33kV, 11kV switchboard, protection and auxiliary assets. Within the new building install at least a 6-panel board, with a minimum rating to accommodate the proposed Primary Transformers and busbar arrangements. The board should consist of two 33kV Primary CBs a 33kV bus section CB and at least three 33kV feeder CBs. Also, it is proposed to plan for additional space on each side of the board according to SSEN planning standards, for additional future connections. Additionally, within the new building, install at least a 12-panel indoor 11kV switchboard, with a minimum rating necessary to accommodate the forecasted load, except for the bus section breaker, which is to be able to accommodate the proposed Primary Transformers and busbar arrangements. The board should consist of 2 Transformer CBs rated at least 2000A a bus section breaker rated at least 2000A and 9 feeder CBs rated at least 630A, with space allocated for future additions to allow new connections.

At this stage, it is proposed that the Substation is to be built at the location highlighted in the figure below.

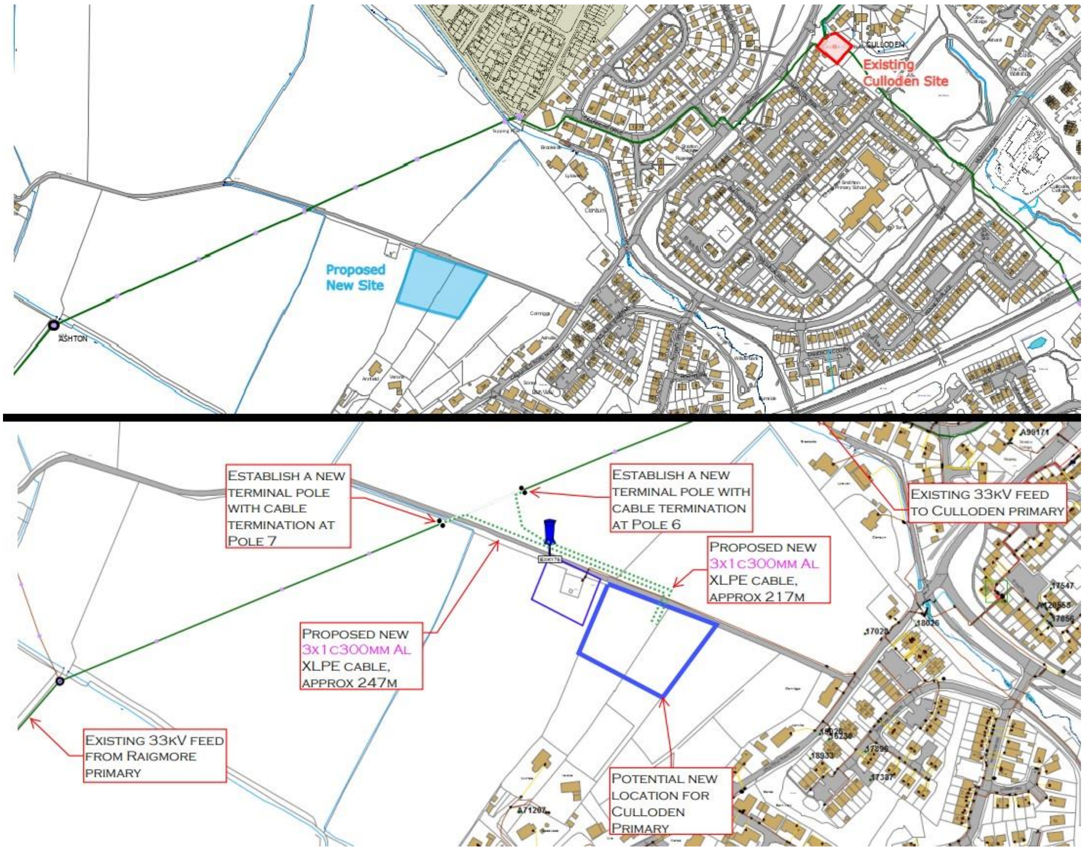


Figure 7.1 - Existing and proposed new site with connection suggestions.

[redacted] other preliminary works, on the other hand, is a good indication of the requirements for a new site. Within the speculative phase, it is proposed the following, where Drawings are referred to within Appendix K.a:

- Utilise one of the existing 33kV cables currently running at 11kV that are laid down on the side of the A9.
- The new board at Longman Drive will need to be extended by an additional 33kV breaker to allow the existing cable to be joined into it.
- Disconnect the existing cable from the Longman switching station and lay it into the new 33kV board of Longman Drive. (Drawings 1A & 1B).
- Utilising this cable provides an easy way to get to the Raigmore primary site.
- At Raigmore primary disconnect the existing cable from Raigmore 020. Straight joint a new section of cable onto the end of the cable from Longman Drive. (Drawings 2A).
- At Raigmore disconnect the existing 33kV cable to Culloden primary, currently connected to 3L5 at Raigmore.
- Straight joint this cable to the end of the cable from Longman Drive. (Drawings 2B).
- This provides a route to the new Culloden primary site utilising the existing OHL to the existing Culloden primary. (Drawings 3A & 3B).
- At the new Culloden primary site. Dismantle a span of the existing OHL between poles 6 &7. Establish two new terminal poles with cable terminations. (Drawings 3C & 3D.)
- Lay a new length of cable from each terminal pole into a new 33kV breaker on the new board. This is complete with the interconnect between Longman Drive & Culloden primaries.
- At the existing Culloden primary site. Straight joint a new section of cable onto the end of the cable from pole 457 and straight joint this cable onto the end of the existing cable from Raigmore (New Culloden primary). (Drawings 4A &4B).
- The last section will be to lay a new length of cable from the new Culloden primary 33kV board back towards the existing Culloden primary site where it will straight joint onto the section of cable laid in from the NOP at Morayston Farm PMR. (Drawings 5A & 5B.)

For related 11kV works, it is proposed to disconnect existing cables from the old Culloden site, straight joint and lay required number of new cables between old and new sites. Following that connect them into the new breakers at new site. Approximate length of cable to reconnect all 9 feeders are assumed to be 6.5km. A high level indication of a possible cable route can be seen in Appendix K.b

It has to be noted that at this stage of the planning, all sizes and details mentioned are to be confirmed at later stages.

[redacted] The breakdown of the assets considered and related OFGEM and internal unit rates can be seen in Appendix J.a.

This option would allow future load growth and additional new connections to proceed and also would ensure the safe and adequate operation of the network.
Considering current lead times for the plant and some switchgear, the expected workload of the design and delivery departments and the generic 3 year that is needed to plan, design construct and energise an EHV Primary Substation, the project is to be started as soon as possible to ensure the energisation of the new site happens before breaching the thermal limits of the existing assets.

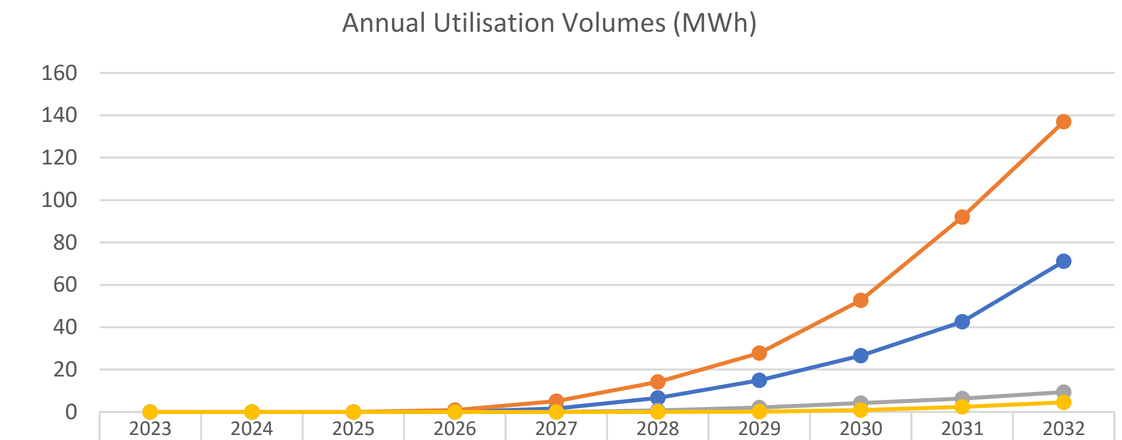
This option is progressed to the Ofgem CBA.

7.4 Option 4: Flexible Solution or Curtailment

In case no flexibility is used, option 2 provides the best option from a technical standpoint. Meanwhile, option 3 explores the possibility of deferring or avoiding investing in assets by using flexibility. This evaluation is performed following the Common Evaluation Methodology (CEM).

With the assumptions in 5.7, the flexibility and related services were studied for a 10-year period, to cover RIIO-ED2 and part of ED3 for possible project overlaps and to determine whether flexibility would be an option to solve load-related issues later too.

Option 2 proposes to expand the network in 2025-26 by adding new transformers and circuits. If this option is deferred, the exceedance of the grid capacity is shown in the Figures below, considering the different DFES scenarios. The annual utilisation volumes presented in the Figure below were calculated and analysed through an internal DFES analysis tool.



	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CT	0	0	0	0	1.628	6.571	14.884	26.606	42.518	71.056
LW	0	0	0	0.867	5.107	14.138	27.730	52.721	91.952	136.971
ST	0	0	0	0	0.025	0.750	2.076	4.180	6.306	9.361
FS	0	0	0	0	0	0	0.195	0.937	2.357	4.530

Figure 7.2 - Annual Utilisation Volumes derived from DFES through an analysis tool

The results of the analysis correlate with the load data presented in earlier sections. Looking at CT and LW scenarios, the need for flexibility or other intervention is starting in 2026 with 0.867 MWh for the LW scenario and in 2027 with 1.628 MWh for the CT scenario. This then exponentially grows with each year, according to the proposed DFES scenarios.

In the Figures below the calculated days per year and hours per day can be seen which gives an indication of the availability requirements for the flexibility services.

[redacted]

This trend is clearly represented through the years in the below Figure as well in terms of forecasted daily service windows required for the flexibility services.

[redacted]

The tabulated parameters used for the Ofgem CEM tool, such as peak network demand, annual utilisation volumes, hours and days required for flexibility, to derive possible deferral periods can be seen in Appendix L. Additionally, the complete Analysis can be seen in Appendix M.

[redacted]

Running the tool for the optimal deferral period provided the results below.

[redacted]

The results above show that short-term flexibility or the deferral of the reinforcements to a short period of time provides an economical solution. On the other hand, it also shows that reinforcement is still needed and cannot be completely supplemented by implementing flexibility. Considering the CT scenario, flexibility may be cost-effective for 4 years, meanwhile, considering the LW scenario this is reduced to 3 years. Based on these scenarios, anything longer than this would not be efficient.

Due to the possible flexibility tendering, discarding the CEM proposed length, this option was progressed to the CBA in order to gain better visibility and understanding of the flexible option. Also, the results above helped to understand how flexibility could be combined to create a hybrid approach to combine flexibility to defer reinforcement to utilise the network more efficiently before reinforcing it.

7.5 Option 5: Combine Flexibility and Reinforcement

Based on the preliminary results from the Ofgem CEM flexibility analysis, an option which includes flexibility to defer intervention with reinforcement for a number of years to enhance the efficient use of the current network was revealed. This solution would allow the circuit to operate until the current infrastructure with minimal to moderate flexibility requirement, meanwhile giving sufficient time to prepare and build the new infrastructure required for the new proposed substation.

Through the above CEM analysis, it was revealed that the best option would be to proceed with this project to employ flexibility between 2026 and 2029 and then proceed with the planned reinforcement. On the other hand, looking at the Flexibility Market Viability in Section 5.7 above, it is understood that the area would not be able to support the 2028/29 requirements with the predicted load growth requirements, which is further demonstrated from a snapshot of the expected MVA exceedance per scenario per year in the Table below, which was derived from the Ofgem CEM tool and Flexibility Market Viability section.

[redacted]

Considering the availability and that the Flexibility Market Analysis was done on a pessimistic approach, the proposal becomes to contract flexibility until 2027 and then proceed with the required reinforcements.

The above means, to plan and organise the project deliverables in a manner that energization or the new substation happens by the end of 2027, not to exceed available projected flexibility and to avoid potential asset overload and breakdown due to conditions. This option provides the best life cycle approach for the existing assets, meanwhile providing the required MVA to ensure the safe and adequate operation of the network.

The associated cost for this option becomes the proposed reinforcement plus the predicted flexibility cost, which was derived from the Ofgem CEM tool after performing the initial comparison between Flexibility and Reinforcement. [redacted] The breakdown of the costs including flexibility can be seen in Appendix J.b.

Since the same reinforcement is proposed as before, it is delayed by one year to ensure delivery by the end of 2027, after the end of the flexibility contract, the released MVA is the same, with the difference of it being released at a later date.

The CEM used to determine the Flexibility need and related costs can be seen in Appendix N.

This option is the preferred option, and it was progressed to the CBA.

7.6 Option 6: Transfer load to neighbouring circuits

An option that might allow for minor to no asset investments is the load transfer. This option would be to keep the existing network topology as is and carry out a load transfer from Culloden Primary to another circuit and or substation.

Through investigation of the surrounding circuits and Primaries, it becomes evident that load transfer to any connecting locations is not possible due to current and forecasted load growth. One additional Substation is being designed and delivered before any new Culloden options are delivered, on the other hand, the released capacity from the new site is already allocated to ease the loading on other surrounding Primaries and to accommodate contracted customers.

Hence this option is not considered viable and has not been taken forward to CBA/CEM analysis.

Associated costs: £N/A

8 Cost Benefit Analysis (CBA)

8.1 CBA of investment options

The options considered for CBA were Option 3, Option 4 and Option 5. Option 1, Option 2 and Option 6 did not progress to this stage due to not fulfilling the requirements of solving the thermal overload at the substation or the delivery of these options is physically not possible. The summary of the options assessed through the CBA can be in the Table below.

Table 8.1 - Summary of Investment Options

Option	Advantage	Disadvantage	MVA release	Costs (C0(b) - £m)	Risks	Outcome
Option 3: Primary reinforcement	A[redacted] problems and provides headroom through the whole lifecycle of the assets	Requires immediate investment, does not consider flexibility or solutions on the whole system	[redacted]	[redacted]	- [redacted] - Possible long lead times or cancellations - Load profile change and proposed circuit not suitable - Less value for money through the whole lifecycle due to changing load requirements	Not Preferred Option
Option 4: Flexibility	Low initial investment and provides a flexible approach depending on actual requirements nevertheless forecast	Uncertainty whether the required flexibility could be met by the existing market and if a new market could be developed with the same speed as demand is predicted. [redacted].	[redacted]	[redacted]	- Uncertainty of existing flexibility market - Uncertainty of future market and how the deviation from DFES would be reflected in conditions. - [redacted]	Not Preferred Option
Option 5: Flexibility and Reinforcement	Additional time for spending CAPEX elsewhere on the network and utilising flexible market with better existing and future asset utilisation. Enhanced overall efficiency per asset.	I[redacted]	[redacted]	[redacted]	- Uncertainty in the local flexibility market [redacted]	Preferred Option

8.2 CBA Results

In addition to the above table, another CBA has been done using the tool provided by Ofgem with pre-specified Discount rates according to the latest HMRC Green Book parameters. The results on NPV through the whole lifecycle of the options can be seen below.

Option no.	Options considered	Decision	Comment	For the chosen option	NPVs based on payback periods					
					10 years	20 years	30 years	45 years	Whole Life	DNO view
3	Capital Reinfromcenet	Rejected	Provides solution to the problem but financially not the most efficient as discards local flexibility market		[redacted]					
4	Flexibility	Rejected	Provides the required felxibility and netowkr support, on the other hand it becomes the most expensive over time, also discards the local flexible market availability							
5	Flexibility and Reinforcement	Adopted	Least cost option through lifecycle of project, incorporating both local flexible market and reinforcement at later stage.							

Figure 8.1 - Ofgem CBA results

From the Figure above that was taken from the Option Summary page of the Ofgem CBA, the preferred option remains Option 5 by providing similar benefits as reinforcement without the need for direct capital investment, meanwhile allowing to use of the local flexibility market. This option still poses certain risks, on the other hand, the ones related to flexibility can be overcome with adequate planning and contracts on flexibility and network support in place, meanwhile providing additional time and room for planning on asset design, procurement and site works.

The corresponding workings and information used can be seen within the CBA tool as Appendix O.

9 Deliverability and Risk

Based on the assessments and studies above on Culloden Primary load-related reinforcement, they have been prepared and engineered to ensure the business plan is deliverable, meets the customer needs and the outcome is the most cost-efficient compared to other options through the whole lifecycle of the project.

Investment Planning	2023/24	2024/25	2025/26	2026/27	2027/28
Primary reinforcement			X	X	X
Assets		Consents, Design and Surveys	Buildings, Procurement and Construction + Flexibility	Finalization and Energization + Flexibility	Connection (end of 2027)

In terms of project-specific risks and deliverability considerations:

- Tight project delivery timelines such as consenting, design and procurement might take up significant time
- Complications and delays to be considered for the proposed new site
- Adequate planning for space and assets at the detailed design phase
- Additional land and consent are required for cable routes proposed for interconnecting existing circuits with the newly proposed site
- Interactivity should be checked with nearby works to ensure minimal disruption and maximum efficiency

- Finances are to be cross-checked as per differences between C0(a) and C0(b) costs due to inflation and RPE and this should be captured at later stages when C2 cost will be derived.
- The load area is currently an active LMA which has limitations on flexibility, that can be provided by existing customers, additionally, the proposed removal of the LMA might speed up the overload process and our prediction of DFES scenarios by changing the existing peak estimates.

Further risk and deliverability will be assessed during Design refinement and detailed Design.

10 Outlook to 2050

Culloden is subject to mandated load scheduling under the DCUSA Schedule 8, Load Managed Areas (LMAs), regulations is currently delivered by the legacy Radio Tele Switching (RTS) system and its Smart meter-based successor.
The move to a Smart meter-based solution for providing LMA based diversity does not, on its own, provide a solution that is compatible with the development of domestic flexibility markets. Consequently, and in the spirit of a Smart and Fair transition, SSEN have committed to removing LMAs during ED2 and ED3.
Three methods used to remove LMAs include:

- Ensuring that any reinforcements driven by LCT growth are sized to ensure that they are not a driver for the continuation of an LMA.
- Improving network monitoring to allow the reduction of the scale of existing LMAs.
- Introducing a new market-based replacement for LMAs, this is expected to take the form of a diversity service.

The geographical area covered by this project is an LMA and as a result we have undertaken checks to ensure that the reinforcement will result in us being able to remove relevant LMA constraints.

Load managed domestic properties in the area account for approx. 11% of all customers.
The reinforcement is sufficiently large to allow the immediate removal of relevant LMAs and will remain unrestricted until we are able to offer a future market-based Diversity service or equivalent.

At this stage, the effect of RTS signal discontinuation on LMA areas is only a prediction and at each location may differ from what is stated in this report. Regardless, the options proposed in this paper should provide adequate solutions to any reasonable LMA-related increased demand.
It should be noted that the impact of LMA on the LV network has not been considered here and would require to be assessed separately.

The recommended option provides a solution for the load growth predicted for 2050, hence nearly the whole lifetime of the assets proposed. Within the initial planning, it will be proposed that adequate space and considerations be met for possible expandability in terms of switchgear bays and site space for the initial build and corresponding infrastructure.

Through the planning and option engineering of the solutions studied, other issues were discovered through the neighbouring circuits due to the forecasted load growth, on the other hand, due to the uncertainty, complexity and nature of those issues, it is deemed not cost-effective to include these within this EJP.

11 Conclusion and Recommendation

This Engineering Justification Paper provides relevant information on Culloden Primary Substation in terms of necessary load-related investment within the RIIO - ED2 price control period.

[redacted] This paper provides option engineering through Common Evaluation Methodology and Cost Benefit Analysis with the help of stakeholder engagement, whole system approach and flexibility market analysis.

The load-related investment at the Primary Substation has been triggered by load growth projected by DFES, both Consumer Transformation and Leading the Way scenarios. To counter the thermal overload for both normal and abnormal network scenarios, out of the proposed options, Option 5 has been selected as preferred which utilises the available local flexibility and helps to delay the proposed reinforcement start date by one year. The summary of the options can be in the Table below.

Option	Advantage	Disadvantage	MVA release	Costs (C0(b) - £m)	Risks
Option 5: Flexibility and Reinforcement	Additional time for spending CAPEX elsewhere on the network and utilising flexible market with better existing and future asset utilisation. Enhanced overall efficiency per asset.	I[redacted]	[redacted]	[redacted]	[redacted]

The recommendation of this option is to proceed with planning and corresponding design work as per the forecasted workload of design and delivery teams. With this approach it can be ensured that the Substation will be ready to be energised before any thermal overload, therefore possible asset outage would occur.

12 References

The documents detailed in Table 12.1 - Scottish and Southern Electricity Networks Documents, Table 12.2 – External Documents, and Table 12.3 – Miscellaneous Documents, should be used in conjunction with this document.

Table 12.1 - Scottish and Southern Electricity Networks Documents

Reference	Title
Previous EJP on Culloden Primary	Engineering Justification Paper - CULLODEN v21-03-26
PR-NET-NPL-007	Planning Standards for 33kV and 22kV Distribution Network
TG-NET-SST-026	Ratings of Oil-Filled Power Transformers
TG-NET-SST-200	Primary Substation Plant Catalogue
TG-NET-CAB-009	Load Ratings of LV to 33 kV Underground Cables - Design Data

Table 12.2 – External Documents

Reference	Title
ENA EREC P2	Security of Supply
Ofgem CEM tool	ON22-WS1A-P1 CEM Tool V 2.2 SSEN
Ofgem CBA tool	RIIO-ED2_Cost Benefit Analysis_Template_0

Table 12.3 – Miscellaneous Documents

Title

Appendix A Definitions and Abbreviations

Table 12.4 – Definitions and Abbreviations

Acronym	Definition
AIS	Air-insulated Switchgear
ASCR	Aluminium Conductor Steel Reinforced
BSP	Bulk Supply Point
CBA	Cost Benefit Analysis
CBRM	Condition-Based Risk Management
CEM	Common Evaluation Methodology
CI	Customer Interruptions
CML	Customer Minutes Lost
CT	Consumer Transformation
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
EJP	Engineering Justification Paper
ESA	Electricity Supply Area
EV	Electric Vehicle
FCO	First Circuit Outage
FES	Future Energy Scenarios
GIS	Geographic Information System
GM	Ground Mounted
GSP	Grid Supply Point
HI	Health Index
IDP	Investment Decision Pack
LCT	Low Carbon Technology
LEP	Local Enterprise Partnership
LI	Load Index
LRE	Load Related Expenditure
LW	Leading the Way
NPV	Net Present Value
OHL	Overhead Line
PM	Pole Mounted
PV	Photovoltaics
RSN	Relevant Section of Network
SCO	Second Circuit Outage
SSEN	Scottish and Southern Electricity Network
SP	Steady Progression

ST	System Transformation
XLPE	Cross-linked Polyethylene

APPENDIX B Sensitivity Analysis

For each investment proposed in this EJP, we have reviewed the annual max demand figures under all DFES scenarios out to 2050. Based on this assessment, we will place this investment into one of the categories from

Category	Description	Applies to this EJP?
A	Schemes where the chosen investment size is large enough to meet peak demand/generation under all net- zero compliant scenarios to 2050 or Schemes where the chosen investment size is large enough to meet peak demand/generation in ED2 and plans for further reinforcement are in place.	
B	Schemes where we would require further future reinforcement of the particular asset(s) being proposed under a more aggressive scenario to 2050	
C	Schemes where the proposed investment is not required under any scenario to 2050 (if any)	
D	Schemes where investment can be deferred until a later date under some scenarios i.e. ST scenario indicates no investment needed until 2030	✓

Justification for Categorisation:

[redacted]

The proposed strategy includes the deployment of flexibility and the reinforcement of the Culloden Primary Substation by 2028.

[redacted] In this case, higher volumes of flexibility services will be procured to cover the exceedance.

Once the reinforcement is complete in 2028, the investment will be large enough to meet the projected peak demand up to at least 2050 under all net-zero scenarios.

The Strategic CBA was also used to compare four strategic across the four decarbonisation scenarios (CT, LW, FS and FS) and identify the strategy with the Least Worst Regret (LWR)

The strategies considered are the following:

1. Strategy 1 (CT compliant) - 1 year of flexibility (2027) and RF (2026- 2028)
2. Strategy 2 (LW compliant) - 1 year of flexibility (2026) and RF (2025- 2027)
3. Strategy 3 (ST compliant) - 3 years of flexibility (2027-2029) and RF (2028 -2030)
4. Strategy 4 (FS compliant) - 4 years of flexibility (2029-2032) and RF (2031 - 2033)

The Regret results are presented in Table 12.5. As shown, Strategy 2 is the one with the LWR, followed by Strategy 1. [redacted] However, it should be noted that the tool does not consider the likelihood of a strategy outrunning. The detailed Regret results for Strategies 1 and 2 are given in Table 12.6.

[redacted]

[redacted]