Scottish & Southern Electricity Networks

RIIO-ED2 Engineering Justification Paper (EJP)

St Marys Primary Substation P2 Compliance Reinforcements

Investment Reference No: 77/SHEPD/LRE/STMARYS

Contents

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

1 Executive Summary

This proposed investment will deliver load related investment of £3.03m during the RIIO-ED2 price control at St Marys primary substation.

The primary investment driver for this scheme is load, specifically an ER P2 compliance issue at St Marys primary substation. This load related issue is apparent under all four of SHEPD's Distribution Future Energy Scenario (DFES) scenarios and investment is required to provide sufficient capacity in order to progress towards net zero, improve the security of supply standard and facilitate renewable generation and the uptake of low carbon technologies (LCT) such as EVs and Heat Pumps on the island of Orkney.

Currently, renewable energy provides 120% of the islands demand, and Orkney has the largest number of electric vehicles per capita in the UK. SHEPD has considered the views and targets of the Orkney Islands council through various DFES stakeholder engagement activities.

St Mary's Primary substation is currently derogated from P2/7 under the SHEPD standards of voltage and security of supply[1]. However, given Orkney's own ambitious progression towards Net Zero and the islands increasing demand on the distribution network, SHEPD believe that rectifying the P2/7 non-compliance is the most appropriate action moving into RIIO-ED2. Without intervention on this scheme, it is expected that existing and future demand on the island would remain without appropriate backfeeding arrangements which may prove a barrier for the islands Net Zero targets with St Marys primary remaining non-compliant with P2.

The EJP considers a range of options to address the P2/7 compliance issues, setting out the options that have been considered and rejected prior to the CBA analysis along with clear rationale for including or excluding each option.

The Cost Benefit Analysis results shown below in table 1 demonstrates that the most cost-effective solution, that delivers the best value for consumers in terms of the 45 years Net Present Value (£m), is option 2 which will installs additional assets onto the network.

Options	Net Present Value (NPV) After 45 Years (£k)	Investment (£k)
Option 2 – Additional Transformer & 33kV OHL line (Preferred Option)	-2,647	3,032
Option 3 – Establish new South Ronaldsay substation & Subsea Cable	-4,478	5,183

Table 1: Option Summary

Our CBA quantifies the benefits associated with each option to support our assessment. For this investment scheme the societal benefits are predominantly attributed to avoided losses and the associated reduction in CO2. For our preferred option 2, the monetary associated benefit is £0.17m over the 45-year period.

Our load related investments contribute very minor CI and CML benefits, as result of their low counterfactual health indices and our licence obligations around overloading of the network. A more detailed explanation can be found in our ***Cost Benefit Analysis Process (Annex 15.8)***.

[1] SHEPD "Distribution Planning: Standards of Voltage and Security of Supply" (P0-PS-037)

Following the optioneering and detailed analysis, as set out in this paper, the proposed scope of works for Option 2 is:

Asset	Volume	Costs
33kV OHL (Pole Line) Conductor) (km)	10	[redacted]
33kV Poles (No.)	142	[redacted]
33kV Transformer (GM)	1	[redacted]
33kV CB (Air Insulated Busbars) (OD) (GM)	1	[redacted]
33kV Switch (PM)	3	[redacted]
6.6/11kV CB (GM) Primary	3	[redacted]
6.6/11kV Switch (PM)	3	[redacted]
6.6/11kV OHL (Conventional Conductor) (km)	9	[redacted]
6.6/11kV Poles (No.)	108	[redacted]
6.6/11kV UG Cable (km)	5	[redacted]
6.6/11kV Transformer (GM)	1	[redacted]
Total		**£3,032k**

Table 2: Investment Summary

This scheme delivers the following outputs and benefits:

- Provides security of supply levels at St Marys primary substation which comply with P2/7.
- Facilitate the continued uptake of low carbon technology (LCT) with the St Marys area and help support the climate change targets of Orkney Council.
- Facilitates the efficient, economic, and co-ordinated development of our Distribution Network for Net Zero.

The cost to deliver the preferred solution is £3.03m and the works are planned to be completed in 2027. This EJP investment sits within our Net Zero Totex ask.

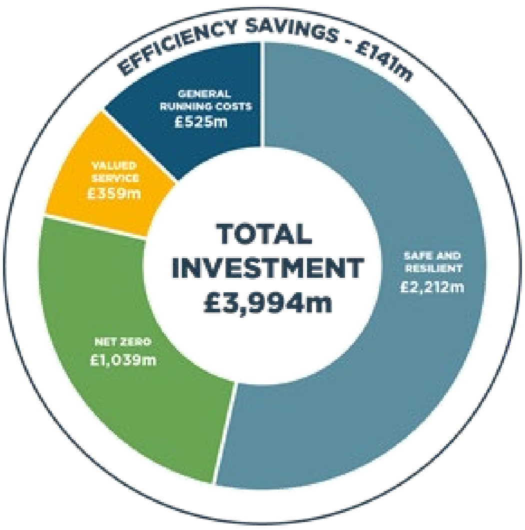


Figure 1: SSEN total investment cost within RIIO ED2

2 Investment Summary Table

The table below provides a high-level summary of this Engineering Justification Paper (EJP) and the Cost and Volume (CV) impacts within SSEN's Business Plan Data Templates.

<table>
<tr><td>Name of Scheme</td><td colspan="3">St Marys Primary Substaition P2 Compliance Reinforcements</td></tr>
<tr><td>Primary Investment Driver</td><td colspan="3">Load – P2/7 Compliance</td></tr>
<tr><td>Scheme reference</td><td colspan="3">77/SHEPD/LRE/STMARYS</td></tr>
<tr><td>Output reference/type</td><td colspan="3">33kV OHL (Pole Line) Conductor
33kV Pole
33kV CB (Air Insulated Busbars) (OD) (GM)
33kV Switch (PM)
33kV Transformer (GM)
6.6/11kV Transformer (GM)
6.6/11kV CB (GM) Primary
6.6/11kV Switch (PM)
6.6/11kV OHL (Conventional Conductor)
6.6/11kV Poles
6.6/11kV UG Cable</td></tr>
<tr><td>Cost</td><td colspan="3">£3.03m</td></tr>
<tr><td>Delivery year</td><td colspan="3">2026/27</td></tr>
<tr><td>Reporting Table</td><td colspan="3">CV1: Primary Reinforcement</td></tr>
<tr><td>Outputs included in RIIO ED1 Business Plan</td><td colspan="3">No</td></tr>
<tr><td rowspan="2">Spend apportionment</td><td>ED1</td><td>ED2</td><td>ED3+</td></tr>
<tr><td>0</td><td>£3.03m</td><td>0</td></tr>
</table>

Table 3: Investment Summary

3 Introduction

Our ***Load Related Plan Build and Strategy (Annex 10.1)***[2] sets out our methodology for assessing load-related expenditure and describes how we use the Distribution Future Energy Scenarios (DFES) 2020 as the basis for our proposals. We have established a baseline view of demand, providing a robust projection of the drivers of load-related expenditure for the ED2 period. Our ex-ante baseline funding request is based on the minimum investment required under all credible scenarios and is strongly supported by our stakeholders. Our plan will create smart, flexible, local energy networks that facilitate the accelerated progress towards net zero – with an increased focus on collaboration and whole-systems approaches.

This investment is a component of our strategic goal of 'Accelerating progress towards a net zero world'.

Section 4 of this Engineering Justification Paper (EJP) describes our proposed load related investment plan for the reinforcement of St Marys Primary Substation in RIIO-ED2. The primary driver considered within this paper is load related P2/7 compliance issues under existing demand which are worsened by forecast demand growth from our stakeholder supported Distribution Future Energy Scenario (DFES).

This EJP provides high-level background information for this proposed scheme explaining the existing network arranges, the load growth forecasts through the Distribution Future Energy Scenarios (DFES) and setting out the need for this project. The Detailed Analysis section of the EJP describes the network studies undertaken, detailing the results which further justify the need of the proposed investment.

Section 5 provides an exhaustive list of the options considered through the optioneering process to establish the most economic 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 6, Cost Benefit Analysis (CBA) Summary, provides the comparative results of all the options considered within the CBA and 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.

Finally, **Section 7** of this EJP also sets out the deliverability of the plan for RIIO-ED2 and this proposed investment.

4 Background Information and Analysis

4.1 Existing Network Arrangement

St Marys is supplied from a single 33kV spur circuit off the Scorradale – Kirkwall No.2 main 33 kV line (see the figure below). The existing 33 kV circuit from Kirkwall to St. Mary's is reported by operations to consist of aluminium conductor steel reinforced (ASCR) overhead line (OHL) and is generally in poor condition. St Mary's has a single 4 MVA 33/11 kV transformer.

St Marys primary supplies three 11 kV feeders via 013, 014, 015. The 11kV feeder 015 has an interconnection with Kirkwall feeders 067 & 057 and feeder 014 is interconnected with feeder 013 at the remote end. 11kV feeder 013 has limited interconnection with feeder 014 and largely consists of a radial circuit which serves South Ronaldsay. In addition to the overall primary substation compliance, this paper will look to rectify the P2 compliance issue of the St Marys 11kV feeder 013.

[2] ***SECTION D: (Chapter 10), Responding to the net zero Opportunity, (Annex 10.1), Load Related Plan Build and Strategy***

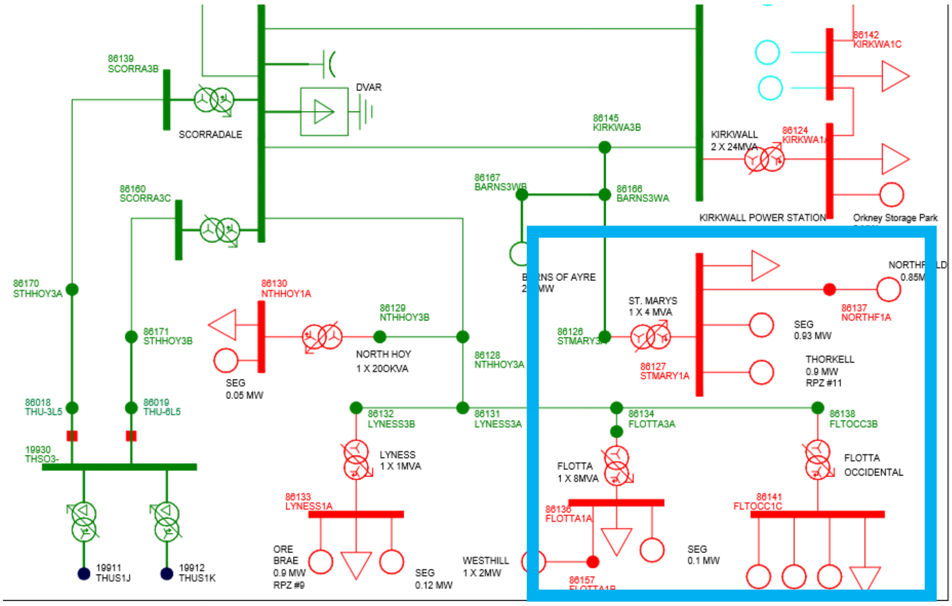


Figure 2: St Marys Network Arrangement SLD.

4.2 Local Area Energy Plan (LAEP)

Orkney has been pioneering the transition to a low carbon economy for decades, with a history of world firsts providing a backstory that illustrates the collective ambition of the Islands community. Sustainable Orkney Energy Strategy 2017-2025 recognises the recent achievement in 2016 of generating 120.5% of Orkney's electrical needs but that Orkney's natural renewable energy resources remain largely untapped and therefore represents a significant contribution to the ambitious government targets towards a low carbon economy[3].

Orkney continues to demonstrate vibrancy as a hub for energy research, development and production. Key to future development is the 'systems approach' to local energy management which will see the increasing significance of innovative storage and supply & demand balancing technologies.

Building on Orkney's successful lead in supporting innovative developments towards local energy systems, that are already providing local solutions to community needs, we will continue to support and drive expertise in the management of energy systems approach that will increasingly include storage technology to co-ordinate supply and demand. The Scottish Government's 'Surf and Turf' and the Fuel Cell and Hydrogen Joint Undertaking (FCHJU) 'BIG HIT' projects hosted in Orkney are already demonstrating such an integrated energy system using Hydrogen as an energy vector for both heat and power.

The reliance of Orkney's economy on imported fuels, particularly for its agricultural vehicles and equipment and marine vessels, still needs to be recognised. It is therefore imperative that the security of energy supply is carefully considered as further transitional steps towards a low carbon economy are taken in Orkney.

Although referenced as a Transport fuel, LNG represents a step towards lower carbon emissions by replacing heavy oil used in shipping and heating. Of significance is Orkney's track record in adopting, and its potential to enable the further development of energy storage options.

[3] https://www.orkney.gov.uk/Files/Consultations/Sustain-Orkney-Energy-Strat-1725/Sustainable_Orkney_Energy_Strategy_Accessible.pdf

Orkney Council's targets around low carbon system are expected to have a significant impact on demand growth within the area. This impact is visible within the SHEPD DFES projections and provides further justification for the need for investment discussed within this paper.

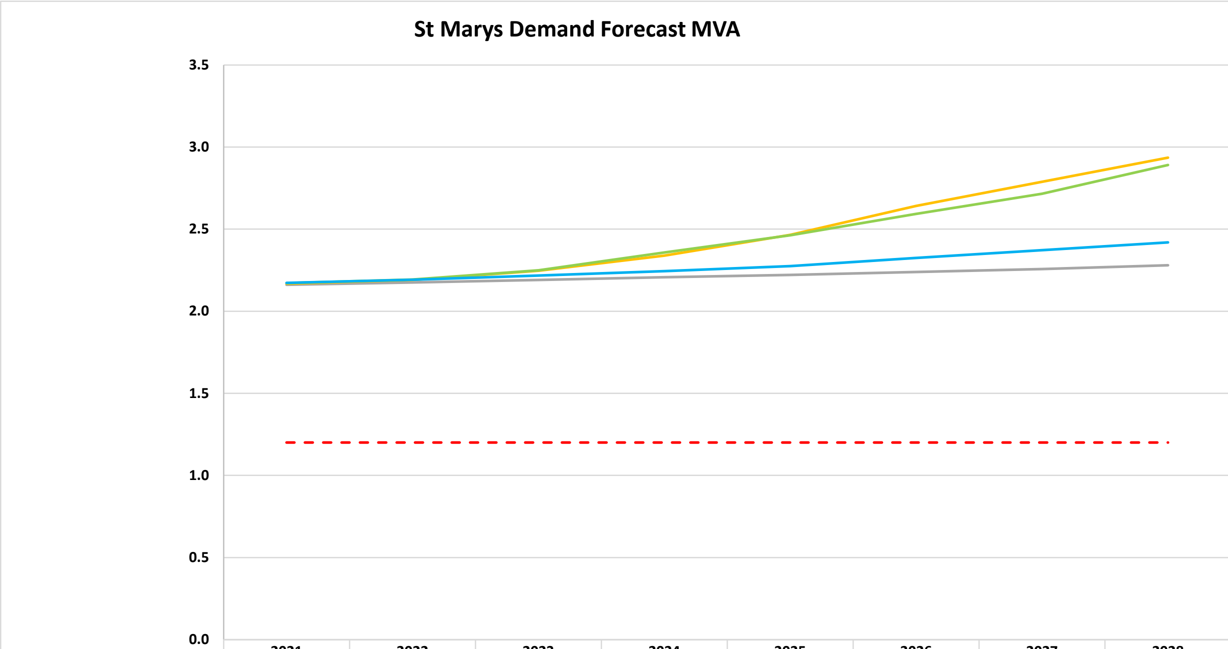
4.3 Demand and Generation Forecast

SHEPD have carried out extensive scenario studies through the Distribution Future Energy Scenarios (DFES) which is based on the National Grid's Future Energy Scenarios (FES) 2020 and local stakeholder input. The DFES comprises of four potential pathways for the future of energy, based on how much energy may be needed and where it might come from. The variables for the four scenarios are driven by government policy, economics and consumer attitudes related to the speed of decarbonisation and the level of decentralisation of the energy industry. SHEPD have worked closely with their partner Regen to develop the forecasts between 2020 and 2050 through enhanced engagement with the local authorities, local enterprise partnerships (LEPs), devolved governments, community energy groups and other stakeholders.

Based on the enhanced stakeholder engagement feedback, SHEPD have chosen Consumer Transformation as the baseline scenario for investment. SHEPD are protecting customers from the impact of forecasting uncertainties through baseline funding only including load related investment required in the first two years in the RIIO-ED2 period unless it is also required by other net zero scenarios. Full details on our DFES methodology, stakeholder input and regulatory treatments of load related investment can be found in the ***Load Related Plan Build and Strategy***[4].

[4] ***Load Related Plan Build and Strategy (Annex 10.1)***

The figure below shows the demand projections in MW of St Marys primary substation under the Consumer Transformation (CT), System Transformation (ST), Leading the way (LW) and Steady Progression (SP) Scenario. The demand projections under all four scenarios exceed the 11kV backfeed limit (1.2MW) if the 33kV supply to St Marys is lost.



	2021	2022	2023	2024	2025	2026	2027	2028
SP	2.2	2.2	2.2	2.2	2.2	2.2	2.3	2.3
CT	2.2	2.2	2.2	2.3	2.5	2.6	2.8	2.9
LW	2.2	2.2	2.2	2.4	2.5	2.6	2.7	2.9
ST	2.2	2.2	2.2	2.2	2.3	2.3	2.4	2.4
11kV Backfeed Rating	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2

Figure 3: St Marys demand projection for winter peak (MVA)

Peak demand at St Marys is expected to increase by approximately 0.7MW from 2019/20 to 2027/28 when following the CT scenario. Currently there is 2.68MW of connected generation at St Marys with a further 5.1MW of new generation planned to connect to St Marys primary substation within ED2.

4.4 Thermal Flow and Voltage Analysis

St Marys Primary substation is currently derrogated from P2/7 under our standards of voltage and security of supply[5]. For the loss of the single primary transformer at St Marys substation a significant proportion of the St Marys load can be supplied from 11 kV interconnection with Kirkwall. However, to keep voltage within acceptable limits under this arrangement it is required to disconnect load on feeders 015 and 013 which estimated at more than 1.3 MW.

In addition to the increased demand not being met by the 11kV backfeed, there is also a significant impact on a large portion of the existing and potential renewable generation feeding into the network, having to be constrained off due to voltage limits. This supports the need for reinforcement at St Marys primary substation to resolve the overloading issues and by making it P2 compliant.

[5] SHEPD "Distribution Planning: Standards of Voltage and Security of Supply" (P0-PS-037)

SYSTEM VOLTAGE LEVELS						
Season	**GSP voltage**	**Demand**	**Generation**	**Study Scenario**	**Highest/ Lowest Voltage**	**Note**
[-]	[p.u.]	[MVA]	[MW]	[-]	[p.u.]	[-]
Winter	1.00	2.5	0	Loss of Transformer	0.96	Load of 1.3MW on feeder 013/015 was disconnected without the additional transformer
Winter	1.00	2.5	0	Loss of Feeder 013	0.95	The additional 11kV feeder and voltage regulator for feeder 013 improve the supply

Table 4: The Results of Thermal Assessment

There are existing voltage issues identified on 11kV feeder 013 and 015 during the intact operation. With loss of St Marys transformer when back fed from Kirkwall the voltage issues worsens. With the proposed new voltage regulator at feeder 013, the voltage at the remote end would be within the limit.

4.5 Fault Level Assessment

Fault levels remain within the existing switchgear ratings.

4.6 Network Analysis Summary

The analysis above strengthens the argument for intervention at St Marys substation within RIIO-ED2 on top of the overall driver to become compliant with P2. The DFES forecasted increase in demand, and in turn the increased reliance on the network will impact a larger number of customers and become more severe considering the LCT uptake. Also, the voltage issues identified will impact the low carbon generators through constraints and therefore slowing both our own and stakeholder ambitions for a Net Zero network.

5 Summary of Options Considered

This section of the report sets out the investment options that were considered to resolve the P2 compliance issue at St Mary's Substation. As described below, a holistic approach is taken to ensure investment options that represent best value for money for network customers are identified.

5.1 Whole System Considerations

We have additionally considered the potential for using Whole System solutions (involving collaboration with third parties) to deliver this investment programme. We set out our assessment in Appendix 3. This follows our standardised approach for embedding Whole System considerations into our load and non-load investment decisions (in line with Ofgem's ED2 business plan guidance), as described in our ***Whole System (Annex 12.1)***.

Our assessment enables us to take a proportionate consideration of Whole System options, based on the feasibility of such options existing and materiality of the costs involved.

In this case, our Whole Systems assessment finds that this programme is not expected to have any wider Whole System interactions and there are no feasible Whole Systems solutions.

5.2 Summary of Options

The table below provides a high-level summary of the four investment options under consideration along with the advantages and disadvantages associated with each option. A more detailed description of each option is then provided within the proceeding sub-sections.

Option	Description	Advantages	Disadvantages	Result
1. Load Transfer	Monitor demand development	Low cost and workload.	Does not increase network capacity. Reinforcement may still be required. Not P2 compliant.	Considered but not progressed to CBA
2. Additional Transformer & 33kV OHL line	To make P2 compliant, new equipment will be added into existing network. This involves: • A new assets of 1 x 33kV transformer at St Marys Primary Substation. • 10 km of 33kV circuit Teed from Scorradale - Kirkwall No. 1 circuit. • 5km of 11kV cable and 9km of 11kV OHL on feeder 013. • 11kV voltage regulator on feeder 013.	Increase network resilience. P2 Compliant. Shorter outage time. Long term benefit. Improve the security of supply for 11kV feeder 013.	Additional land purchase could be required at St Marys.	Taken forward to CBA (the Preferred Option)

3. Establish new South Ronaldsay substation & Subsea Cable	To make P2 compliant, new equipment will be added into existing network. This involves: • A new asset of a 33kV Primary Substation and 33kV and 11kV circuit breakers. • 11.1 km 33kV circuit including 3km subsea cable. • 11kV voltage regulators on feeder 013 and 015.	Increase network resilience. P2 Compliant. Shorter outage time. Provide new supply from Flotta and Improve the supply security for South Ronaldsay area.	New land purchase will be required at new primary substation and it may incur large civil costs. Subsea cable route could be difficult. Required new control strategy.	Taken forward to CBA
4. Flexibility Solution	Flexible service contracts to reduce peak demand and defer capital investment	Utilising existing network capacity.	Uncertainty of securing participants. Reinforcement may still be required.	Considered but not progressed to CBA

Table 5: Summary of Primary Switchgear Investment Options

5.3 Option Analysis

5.3.1 Option 1: Load Transfer

St Marys Primary is interconnected at 11kV to a nearby primary substation at Kirkwall. Due to limitations of 11 kV feeders, there is not enough capacity to facilitate load transfer of the forecast increased demand during RIIO-ED2. This option carries a significant amount of risk and may result in increased CIs, CMLs and continued non-compliance with ER P2. Given the increase in the demand of new and existing customers will be impacted far greater than RIIO-ED1, this option ensures St Marys substation remains an LI 5. For this reason, the load transfer option has been deemed not viable to deliver the required P2 compliance for customers.

5.3.2 Option 2: Additional Transformer & 33kV OHL line (The Preferred Option)

Install an additional 4.0MVA 33/11 kV transformer at the St Marys substation. This would increase the firm capacity of the St Marys primary substation and hence would enable power to be restored for a transformer outage condition.

In order to improve redundancy for a circuit outage on the 33kV spur on the Scorradale – Kirkwall No.2 main circuit, the new transformer would need to be supplied via a new 33kV OHL of 100mm Cu (10km) with winter rating of 17.4MVA derived from Scorradale – Kirkwall No.1 circuit. The proposed OHL route is shown in the figure below.

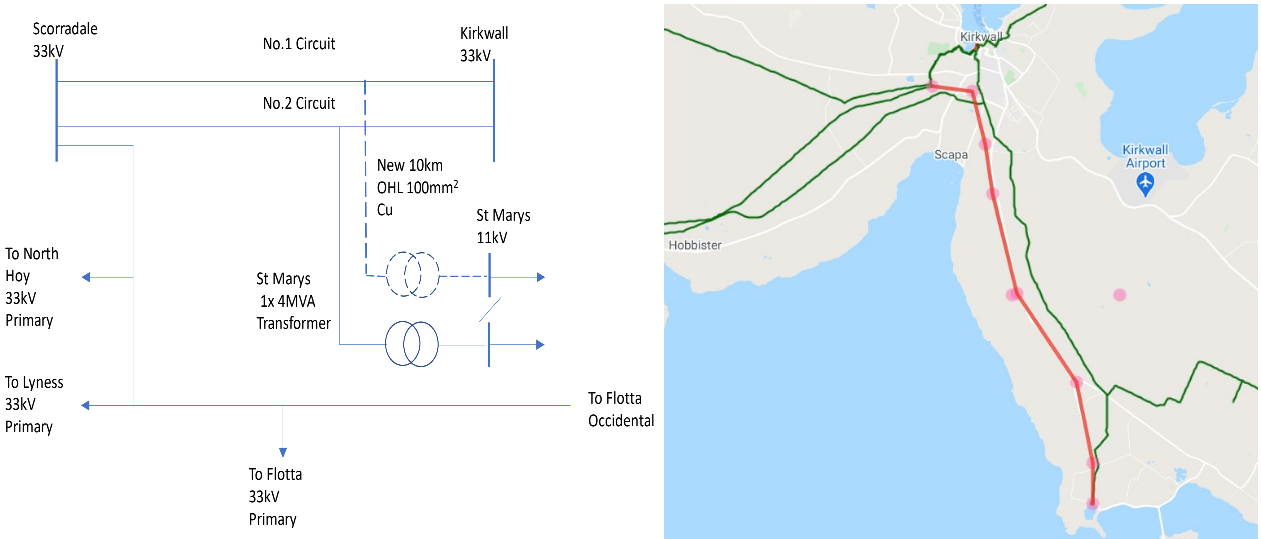


Figure 4: The new 33kV circuit fed to St Marys.

There are no 33kV N-1 thermal flow issues for this option.

To improve the security of the supply on feeder 013 specifically, it is expected to install a new 5km cable of 150mm Al and 9km OHL of 70mm Cu from St Marys primary substation to the location near St Margarets Road. This option will require a full survey to access the new 11kV cable route across the bridges to South Ronaldsay.

To mitigate the voltage issues on 11kV feeder 013, it is proposed to install a bi-directional 2x300 Amp voltage regulator in proximity to St Margarets Road utilising new pole. The proposed 11kV arrangement is shown in the figure below. This option will improve St Marys substation to an LI 1.

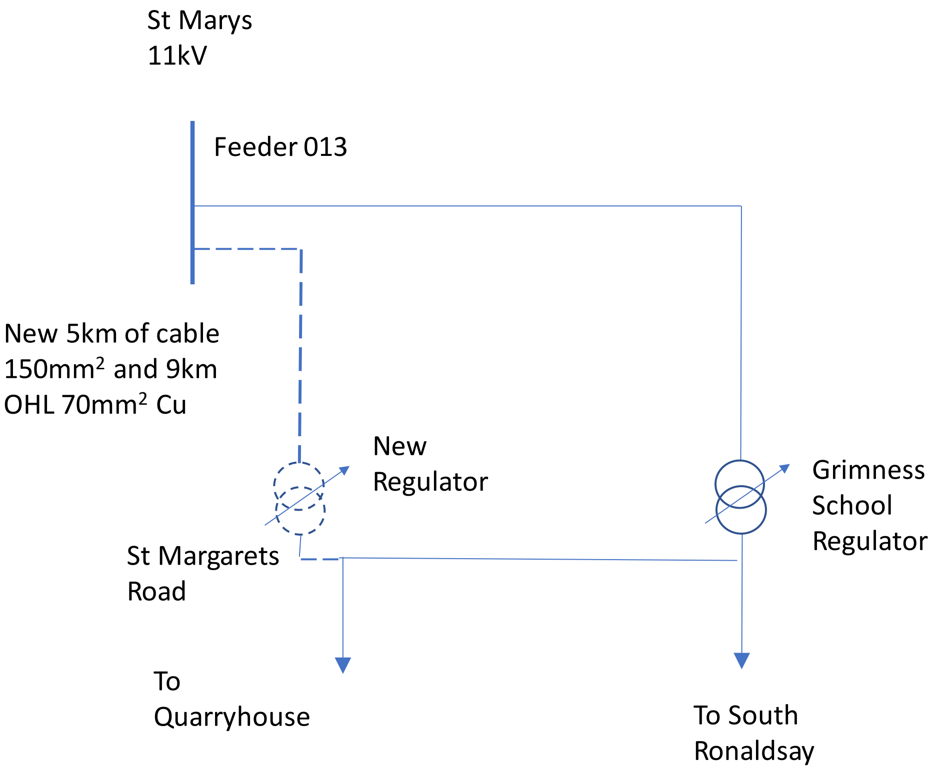


Figure 5: The new 11kV supply to South Ronaldsay.

5.3.3 Option 3: Establish new South Ronaldsay substation & Subsea Cable

This option installs 33kV subsea link from Flotta and new primary substation on South Ronaldsay. The preliminary route for the new 33kV circuit (including subsea section) is shown in the figure below.

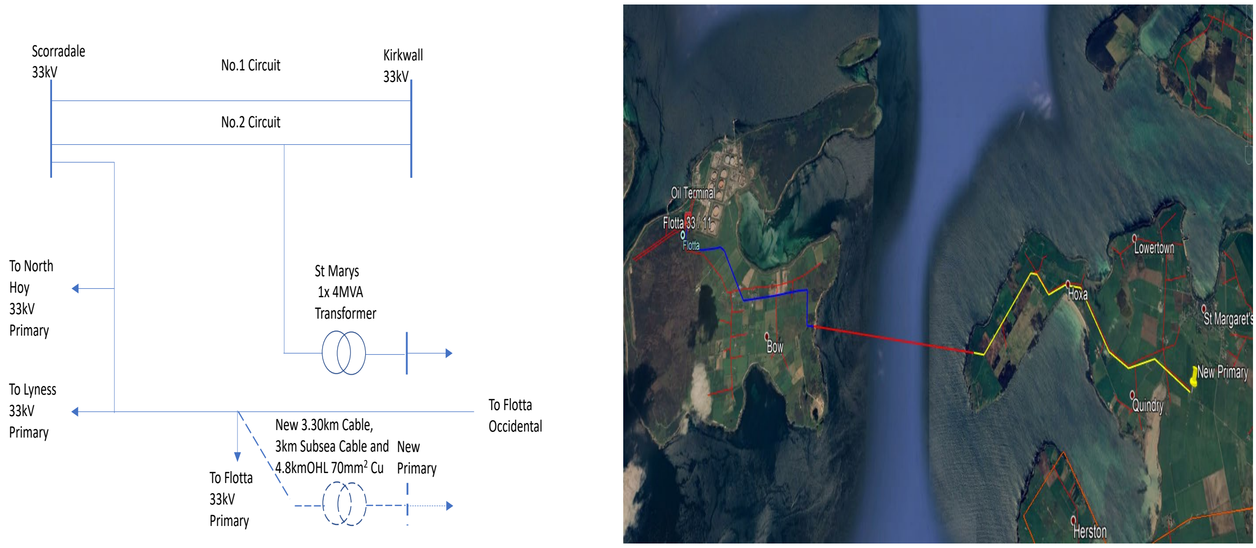


Figure 6: New circuit route between 33kV subsea link and the new primary substation.

The works associated with this are detailed below:

- Tee off existing 33kV circuit from Pole 13 Sutherland on Scorradale – Flotta 33kV circuit, or from establishment of new pole in proximity.
- Installation of approximately 3.3km of 3 x 1c 300mm Al 33kV cable circuit from tee to start of subsea-cable section on east coastline of Flotta.
- Water crossing approximately 3km from Flotta to South Ronaldsay, cable will make land at Southern end of Hoxa.
- Overhead line section to be run from cable landfall at Hoxa to proposed new substation. Overhead section on South Ronaldsay approximately 4.8km in length based on preliminary substation location.

Establishment of new substation will consist of installation of following major network assets:

- 33kV circuit breaker with isolator switch
- 2 No. 11kV circuit breaker
- 4 MVA 33/11kV primary transformer

To mitigate the voltage issues on feeder 15, it is proposed to install a bi-directional 2x100A voltage regulator in proximity to the tee–off to secondary transformer 335 utilising either a new or existing pole. To mitigate the voltage issues on feeder 13, it is proposed to install a bi-directional 2x200A voltage regulator in proximity to the pole of Norton G838 utilising either a new or existing pole. Taking forward the option to establish a new primary substation on South Ronaldsay ensures that the voltage regulator would only be a requirement with the new substation out of service. In this situation, the running arrangement will revert to the present arrangement with St Mary supplying feeder 013 in its entirety. This option will improve St Marys substation to be LI 1.

5.3.4 Option 4: Flexible Solution

This option considers utilising customer generation capacity to actively manage the peak power flow on existing assets. This will allow SHEPD to utilise the existing network effectively and may defer or remove the need for reinforcement action.

The figure below shows that the peak demand at St Marys Primary exceeds the 11kV backfeed rating in 2027/28 for approximately 14 hours over the winter months with a requirement between 0-2MVA. It shall be noted that the peak demand appears in the late evening.

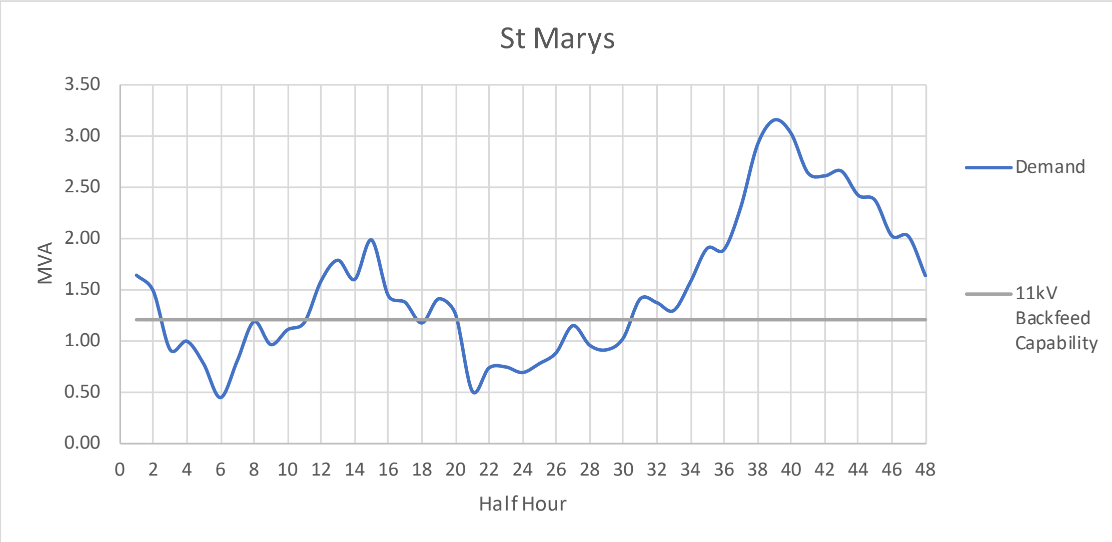


Figure 7: St Marys peak demand 2027/28 without flexibility services.

The Baringa CBA model [6] has been also used to assess if there is any benefit on deferring the reinforcement. The most economically viable conventional solution was obtained from the CBA and input into the Common Evaluation Methodology (CEM) Flexibility CBA to determine if there are economic benefits in deferring the capital investment.

The CEM framework evaluates options around timing of network investments, account for:

- the range of different options available (e.g., reinforcing the network, using flexibility, or doing nothing);
- the time periods in which actions can be taken; and
- the existence of uncertainty, and the impact of incremental information which becomes available over time.

The MW exceedance, the daily and annual overload hours (Table 6) and the flexibility unit costs of £150 per MW per hour and £150 per MWh were used as input parameters in the CEM CBA model (full details of the flexibility methodology can be found in the ***Load Related Plan Build and Strategy (Annex 10.1)***

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Hrs/day required	0	0	0	0	0	0	0	15	15
Days/yr required	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
Utilisation (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	382.0	417.0

Table 6: Estimated dispatch requirements for flexibility solution

[6] https://www.energynetworks.org/assets/images/Resource%20library/ON20-WS1A-P1%20Common%20Evaluation%20Methodology-PUBLISHED.23.12.20.pdf

Flexibility services could be used to reduce the peak demand forecast but it is estimated that no reinforcements could be deferred (shown in the figure below).

Overall NPV of deferral	**Optimal length of baseline deferral (years)**	**NPV of optimal deferral**
Flexibility under CT	Baseline	£0
Flexibility under ST	Baseline	£0
Flexibility under SP	Baseline	£0
Flexibility under LW	Baseline	£0

Figure 8: Net benefit of deferring reinforcement.

Despite our commitment to the Flexibility First approach, in this scenario the current assessment has concluded that Flexibility will not mitigate the P2 compliance issue and adds no financial benefit through deferring the required works. However, flexibility may provide OPEX benefits to SSEN and our customers during scheme delivery by;

a) Avoiding/reducing the risk of outages during planned works through load/generation management
b) Avoiding/reducing the need for Mobile Diesel Generation in planned or unplanned outage scenarios
c) Reducing the scale of the works through the implementation of a 'Hybrid' scheme, part reinforcement and part Flexibility.

These opportunities will be reviewed, and Flexibility secured should the CEM Framework CBA prove a positive benefit, with justification of the decisions/reviews presented as required.

Further detail of our Flexibility First approach and assessment methodology can be found in our ***DSO Strategy (Annex 11.1) Appendix F - Delivering Value through Flexibility.***

6 Summary of Cost Benefit Analysis (CBA)

This section provides an overview of the results from the Cost Benefit Analysis (CBA). This detailed exercise has been undertaken to support the investment strategies discussed within this EJP.

6.1 CBA of investment options

Ofgem's RIIO-ED2 standard CBA template was used to assess costs and benefits of the conventional options for each circuit individually. Capital reinforcement costs, CI/CML penalties, network losses and other societal benefits are the key parameters used in the CBAs of the three options progressed. The customer interruptions / customer minutes lost (CI/CML) were calculated based on the potential overload and the probability of a failure.

Further information on our Cost Benefit Analysis (CBA) approach is set out within our ***Cost Benefit Analysis Process (Annex 15.8)***.

6.2 CBA Results

The CBA results below demonstrate that the most cost-effective solution is option 2, 'Additional Transformer & 33kV OHL line', as it has the least NPV against the required investment. It is clear that the investment reduces the CI's at St Marys Substation immediately within RIIO-ED2, while providing efficient and enduring long-term security of supply as we move towards a Net Zero network. Therefore, based on the CBA results option 2 is preferred solution to address the P2/7 compliance issue.

Summary of Cost

Options	Unit	2024	2025	2026	2027	2028	ED3+	Total £k
Option 2 – Additional Transformer & 33kV OHL line (Preferred Option)	**£k**	0	0	0	3,032	0	0	3,032
Option 3 – Establish new South Ronaldsay substation & Subsea Cable	**£k**	0	0	0	5,183	0	0	5,183

Cost Benefit Analysis comparisons

Options	Net Present Value (NPV) After 45 Years (£k)	Investment (£k)
Option 2 – Additional Transformer & 33kV OHL line (Preferred Option)	-2,647	3,032
Option 3 – Establish new South Ronaldsay substation & Subsea Cable	-4,478	5,183

6.3 Options Summary

Option 1 is the lowest capital costs and may appear to be the attractive option. However, this option does not provide sufficient capability to meet the projected network requirements and is not considered a cost-effective long-term solution.

Option 4 does not provide the required level of security of supply through the use of Flex.

The only remaining options which satisfy the P2 compliance requirements are options 2 and 3. These options both provide the required security of supply through additional assets at St Marys substation. Option 2 benefits from only requiring 33kV OHL, rather than installing a subsea cable for option 3 which comes at a higher cost.

Therefore, option 2 is the preferred solution.

6.4 Costing Approach

Our RIIO ED2 Business Plan costs are derived from our outturn RIIO ED1 expenditure. We have modified costs per activity, capturing and reporting those adjustments in our cost-book. By tying our costs back to reported outturn, real life data has been used which provides multiple data points both SSEN and the Regulator can use to benchmark costs efficiently.

It provides a high level of cost confidence in our Business Plan cost forecast for RIIO ED2. Through our benchmarking analysis, we recognised that not all Non-Load related RIIO-ED1 actual unit costs sit within the upper quartile efficiency band. Where this is the case, we have applied a catch-up efficiency to those cost categories.

Further detail on our unit cost approach, cost efficiency and cost confidence for RIIO-ED2 can be found within our ***Cost Efficiency (Annex 15.1)***[7]. Following our draft Business Plan, we have continued to develop project scopes and costs, utilising valuable stakeholder feedback. We have included developments of our Commercial Strategy within the updated project scope and delivery strategy.

[7] ***Cost Efficiency (Annex 15.1)***

7 Deliverability and Risk

Between our draft and final Business Plans we have carried out a more detailed deliverability assessment of our overall plan as a package and its component investments. Using our draft Business Plan investment and phasing as a baseline we have followed our deliverability assessment methodology. We have assessed any potential delivery constraints to our plan based on:

- In-house workforce capacity and skills constraints based on the our planned recruitment and training profile and planned sourcing mix as well as the efficiencies we have built into our Business Plan ***(detailed in our Workforce Resilience Strategy in (Annex 16.3)*** and ***Cost Efficiency (Annex 15.1)***
- Assessment of the specific lead and delivery timelines for the asset classes in our planned schemes
- We have evaluated our sourcing mix where there were known delivery constraints to assess opportunities to alleviate any constraints through outsourcing
- We have engaged our supply chain ***Supply Chain Strategy (Annex 16.2)*** to explore how the supply chain could support us to efficiently deliver greater volumes of work and how we could implement a range of alternative contracting strategies to deliver this
- We have also engaged with the supply chain on the delivery of work volumes that sit within Uncertainty Mechanisms to ensure we have plans in place to deliver this work if and when the need arises
- Specific to load schemes: We have carried out flexibility assessments at all voltage levels in order to understand when we can defer reinforcement through paying for flexibility services, therefore ensuring our investment profile is deliverable and at the lowest cost to consumers see ***Flexibility within Load Related Plan Build and Strategy (Annex 10.1)***
- We have assessed the synergies between our planned load, non-load and environmental investments to most efficiently plan the scheduling of work and minimise disruption to consumers

This investment scheme is part of the wider load-related investment portfolio in RIIO-ED2. SSEN have developed a strategy to deliver a much larger volume of work in comparison with the level of investment in ED1. We have engaged with our supply chain to negotiate the most effective unit costs and we have taken measures to ensure we secure a future workforce with the right skills and competencies to deliver capital projects in ED2.

In ED1, SHEPD have delivered a number of 33kV and 11kV OHL projects using internal workforce. The experience and skills acquired from these projects lay the foundation for the delivery of the proposed option within this paper.

As the preferred option requires the 11kV cable route across the bridges to South Ronaldsay, the constraints on the cable route can lead to the risks for the scheduled delivery. The outage planning and engineering challenges on the 11kV cable shall be managed in an efficient way to mitigate the potential risks for the proposed option within this paper.

This scheme was originally included in our baseline for delivery during the RIIO-ED1 period, however, delivery constraints alongside the existing derogation means it is not economic or efficient to progress with this project within RIIO-ED1. Our decision to defer this scheme means that, where necessary, we are able to use this allowance to efficiently deliver other projects which may have arisen within RIIO-ED1. This allows us to continually meet the requirements of our network and the needs of our customers throughout the price control.

8 Conclusion

This EJP has raised the need for load related investment on St Marys Primary substation within the ED2 price control period. This need for investment is driven by the existing non-compliance with P2/7 and is further justified by the forecasted demand increase. To avoid security of supply issues for customers on St Marys Primary, reinforcement is proposed to remove this non-compliance.

Four investment options have been considered and the preferred solution involves a installing a 4.0MVA transformer at St Marys primary substation and also installing 10km of 33kV OHL, 5km of 11kV UG cable, 9km of 11kV OHL and 1 no. 11kV regulator. All options are supported by a Cost Benefit Analysis (CBA) which provides further breakdown of economic viability over a 45-year period. The preferred option will improve St Marys primary substation to be LI 1.

The proposed ED2 investment with the combined scheme total of £3.03m. It is proposed that all reinforcement is carried out in the 2026/27 financial year to minimise the risk of thermal overload and network non-compliance.

Appendix 1: Geographic Views

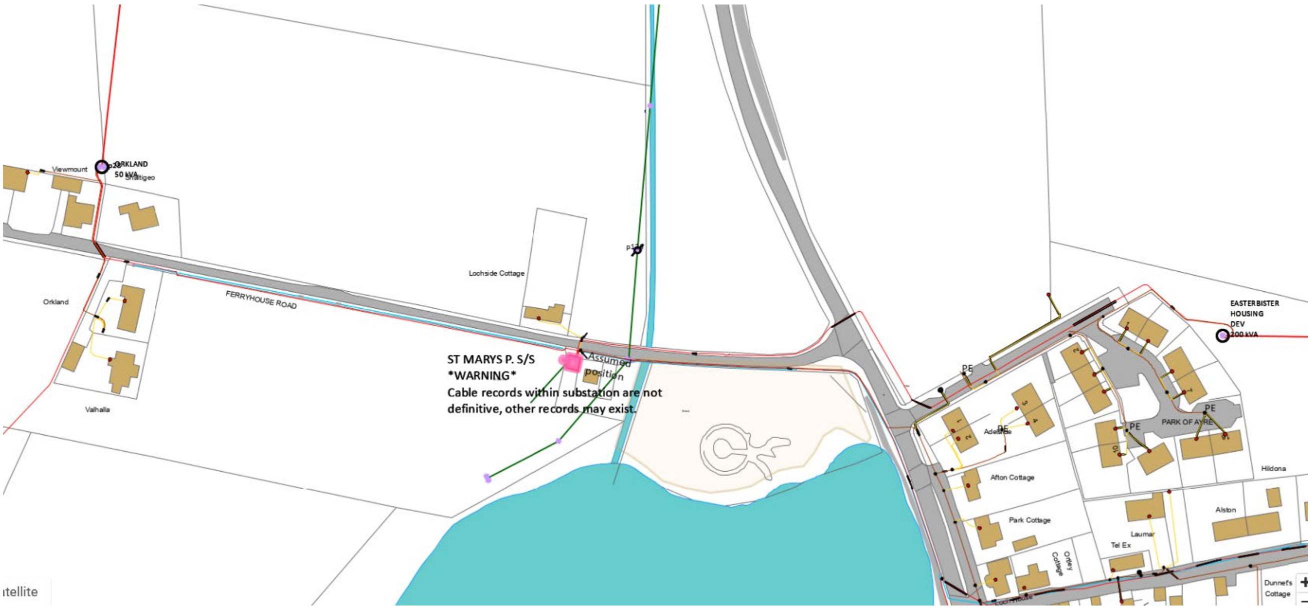


Figure 9: St Marys Primary Substation.

Appendix 2: Relevant Policy, Standards, and Operational Restrictions

The policies, manuals and standards and operational restrictions relevant to the content of this paper.

Policy Number	Policy Name / Description
TG-NET-OHL-010	Load Ratings of Overhead Lines – Data Sheet
TG-NET-OHL-012	Short Circuit Ratings of Overhead Lines – Data Sheet
TG-NET-OHL-104	Electrical Constants for Overhead Lines- Data Sheet
TG-NET-CAB-009	Load Ratings of LV to 33kV Underground Cables – Design Data
TG-NET-CAB-010	Electrical Constants for LV to 33 kV Underground Cables- Data Sheet
TG-NET-CAB-011	Short Circuit Ratings of 6.6kV to 33kV Underground Cables - Design Data

Table 7: Relevant documents

Appendix 3: Whole Systems consideration

In augmenting our decision-making processes to consider Whole System solutions, we have introduced an assessment to identify where a Whole Systems CBA would be a useful decision-making tool for ED2 load and non-load schemes. While our work with the ENA to undertake Whole Systems CBAs is ongoing, we have introduced the 'Whole Systems CBA test' to identify where a scheme may be suitable for a Whole Systems CBA to be conducted. Where a Whole Systems CBA is determined to be a useful decision-making tool, these would be conducted in addition to the standard Ofgem CBA and/or SSEN's flexibility CBA. We have introduced this test in line with Ofgem's expectations for "proportionality when submitting a Whole System CBA. For example, smaller or simple projects following the standard CBA template, whereas larger or more complex projects requiring bespoke analytical approaches" (Ofgem BPG, section 4.28, p.34).

The 'Whole Systems CBA test' involves assessing each investment scheme of over £2m (the threshold to develop an EJP for load and non-load investments) against 5 tests. These 5 tests help determine whether a Whole Systems CBA is a useful decision-making tool based on the characteristics of the scheme, including whether it will have wider cross sector or societal impacts.

Details on each of the tests are provided in case study 6 in ***Whole Systems (Annex 12.1)***. Tests 1-3 are aligned with the ENA's guidance for Whole System CBA tests. We have added Tests 4 and 5 to clarify whether a Whole Systems CBA is required based on the materiality / proportionality of the investment (Test 4) and whether a flexibility CBA only is sufficient (Test 5). Table 10 below outlines our Whole Systems CBA test for St Marys Primary P2 Compliance.

Scheme	Test 1: Are there Whole Systems interactions, or is there potential for it?	Test 2: Could a Whole Systems CBA drive you to make a different decision?	Test 3: Is a Whole Systems CBA reasonable?	Test 4 - Is the project valued at over £2m?	Test 5 - Is the investment plan related to procuring flexible solutions only?
St Marys Primary P2 Compliance	No – We consider there to be limited potential for Whole Systems interactions with third parties to deliver this investment programme, and accordingly we do not consider there to be potential for Whole Systems solution(s).	No – As noted under Test 1 we do not consider there to be potential for Whole Systems solution(s) in this case.	No – As noted under Test 1 we do not consider there to be potential for Whole Systems solution(s) in this case.	Yes	No

Table 8: Whole Systems CBA test for St Marys Primary P2 Compliance

As the result of tests 1, 2 and 3 above is "No", a Whole Systems CBA is not required for this investment. It is not expected to have any wider Whole System interactions or potential Whole Systems solutions.