Recommendation – Public Version

Shetland Enduring Solution – DSO Contribution

Scottish & Southern Electricity Networks

# Scottish Hydro Electric Power Distribution

# Shetland Enduring Solution

## DSO Recommendation

## May 2019

# Contents



This document is an amended version of SHEPD's original Recommendation which was submitted to Ofgem in November 2018. The amendments have been limited to those required to protect highly confidential and commercially sensitive information. In reading the Recommendation, stakeholders should also make reference to the Recommendation Addendum and Baringa Report which are published alongside this document. Where there are updates to Recommendation information, these are highlighted within this document using bracketed red script (e.g. (**x**)), and explained within the relevant sections in the Addendum.

# Executive summary and recommendation (a,b)

This document summarises Scottish Hydro Electric Power Distribution's (SHEPD) recommended whole system solution to secure supply for Shetland at lowest cost to consumers in line with its obligations under Special Licence Condition 2Q, and further to Ofgem's associated Directions to SHEPD. The need to secure sustainable supply arrangements for Shetland is already acknowledged and is driven by the closure of existing generation facilities at Lerwick Power Station (LPS)[1].

- SHEPD is recommending to Ofgem that enduring security of supply for Shetland is best achieved through connection of SHEPD's distribution network on the islands to the proposed Scottish Hydro Electric Transmission (SHE Transmission) HVDC link submitted to Ofgem under the Strategic Wider Works mechanism (Special Condition 6i).

- SHEPD has assessed what the fair value of the transmission link is to its distribution customers, **£249m** (**a**), and is recommending that it contribute this sum to the cost of the transmission link construction as a single payment on completion of the link by the relevant Transmission Operator (TO). SHEPD is preparing to submit its application to connect to a new grid supply point on Shetland.

- This recommendation represents an economic benefit to customers through reduced network costs of **£145m** (**b**).[2]

To arrive at this whole system recommendation, SHEPD has designed and followed the comprehensive assessment process, outlined to Ofgem on 3rd May[3], which is summarised below. The assessment process demonstrates that SHEPD has considered relevant viable technical options from both the distribution and other energy sectors, has been based on benchmark costs and, if implemented, secures the best value outcome for distribution customers.

## Summary of assessment process

### Alternative technical solutions and benchmark cost

In carrying out analysis to update the 2017 Shetland New Energy Solution (NES) cost benchmarks we have identified, using a methodology developed by Baringa Partners, that the present value (PV) cost to consumers to provide a distribution link would be £394m. This would be the reasonable expected PV of the best value, technically compliant solution if a competitive process were to be re-run in 2019. This solution remains of materially better value to consumers than the alternative islanded fossil fuel-based solutions which have also been evaluated and valued by Baringa and Mott MacDonald.

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[1] The need to identify and put in place an enduring solution was originally identified in 2010 and further detailed in the range of Shetland NES publications during 2016 and 2017. Current environmental permissions to operate new engines at LPS in the current operating regime will expire at the end of 2025. The extended operation of LPS beyond 2025 is dependent on the ability to comply with future emissions requirements.

[2] Present value terms.

[3] *2018-04-30 Ofgem bilateral Shetland enduring solution May 3 2018*, presentation by SHEPD to Ofgem

### What is the Fair Value to distribution customers of a transmission connection

SHEPD and its consultants have identified a number of "fair value tests" to identify what value distribution consumers should place on securing a transmission solution. SHEPD recommends a "stacked value test" which takes a bottom-up approach to identifying and valuing services provided. This approach is aligned with the NES competitive tender which sought bids from parties to provide services to the distribution network. It values the services that the transmission link would now provide to the Shetland archipelago.

These services and their assessed values are summarised in Table 1 below (see Section 5 for detail):

**Table 1: Stacked fair value contribution to a whole system solution**

| Service | Value of service (a) |
|---|---:|
| Year-round control services | £115.6m |
| Reduced losses | £9.7m |
| Peak demand support | £123m |
| **Total contribution value** | **£249m** |

### Best value for customers

SHEPD's process has identified the benchmarked costs of the best alternative security of supply solution, the PV of a distribution link at £394m. This represents the counterfactual cost to consumers if connection to a transmission link is not successful. SHEPD has, with advice from its consultants, assessed that the value provided by the transmission link is £249m. A transmission link therefore represents the best value option for consumers and is the basis for SHEPD's recommendation that it should, on behalf of distribution customers, make a contribution to the cost of the transmission link.

### Contribution methodology

SHEPD proposes that the contribution of £249m is implemented by making a one-off, upfront payment to the TO. This capital contribution would be funded through an increase in the RAV of the DSO and a consequential reduction in the RAV of the TO. The contribution would have the effect of reducing the capital cost confirmed to National Grid Electricity System Operator (NGESO) for the purposes of calculating the local circuit element of the Transmission Network Use of System (TNUoS) charge and be recovered via distribution revenue (Distribution Use of System (DUoS) or Hydro Benefit Reduction Scheme (HBRS)).

### Standby requirements

SHEPD will also need to determine standby arrangements required to provide back-up to a transmission link solution. For the purposes of this assessment, an updated cost benchmark from the 2017 NES process has been used. SHEPD considers that the technical requirements of such a service are consistent irrespective of whether the primary supply arrangements are provided by a transmission or distribution link to the GB mainland.

### Application of whole system approach

This recommendation addresses the needs of Shetland consumers in line with SHEPD's licence obligations. However, we propose that the whole system, cost avoided principle leading to a contribution from the DSO can also apply to other Island and mainland network scenarios.

**Engaging stakeholders (c,e)**

Throughout 2018 SHEPD has consistently engaged with relevant stakeholders. This engagement has been tailored for each stakeholder and has been designed to enable the capture of advice and guidance which would improve SHEPD's overall recommendation process. Primary communication has been with the Ofgem RIIO-ED1 Costs and Outputs and the New Transmission Investment teams. They, in turn, have passed on updates within Ofgem. SHEPD has engaged with advisors within BEIS and the Scottish Government, seeking their views on the approach to recommending a sustainable solution for Shetland. We have also engaged with the other potential Shetland connecting parties, in particular remote island wind generators, to communicate the principle of the process being followed. Finally, SHEPD has been in regular contact with SHE-T to ensure that correct information and data relating to the Shetland Needs Case have been taken into account in developing this recommendation.

**Next steps (d)**

This recommendation is intended to supplement the information contained within the summary document, to allow Ofgem to complete its review of the approach and recommendations. SHEPD hopes that Ofgem will take into consideration the innovative thinking proposed in the context of a whole system solution, whilst at all times retaining focus on maintaining security of supply and achieving best value for all (GB and Shetland) consumers. SHEPD looks forward to presenting these proposals to Ofgem and other stakeholders over the coming weeks.

In order to meet the tight timescales driven by the CfD process, the following stages are considered necessary to be met:

- Ofgem review of recommendation and SQ process - Nov 2018
- SHEPD recommendation workshop with Ofgem and consultants - 20 Nov 2018
- Ofgem representation of decision at GEMA board – December 2018
- Ofgem minded-to consultation on costs / methodology of recommendation - Dec 2018 – Jan 2019
- Ofgem decision on costs / methodology – Feb 2019
- Pre-CfD auction implementation – Feb – Apr 2019
- **CfD auction opens – May 2019**

# 1 SHEPD's approach – building blocks

## 1.1 Historical context

1.1.1 In May 2017, SHEPD made a recommendation to Ofgem (subsequent to the 2013 Integrated Plan recommendation) proposing the securing of contracts with National Grid Shetland Link Ltd (NGSLL) and Aggreko for a solution based on a mainland distribution link and standby power plant. The recommendation was the culmination of the NES tender process, which had commenced in late 2014, further to Ofgem's 2014 Direction.[4]

1.1.2 In November 2017, Ofgem rejected the costs of the recommended solution. They did so on the basis that:

i. following the publication of changes under the IED, LPS (with supporting measures) could provide security of supply on Shetland in the near-term at a cost significantly below that of the NGSLL-Aggreko solution, for the period 2021-2025;

ii. in October 2017, the Government announced that (subject to receiving State Aid approval) wind farms on remote islands such as Shetland would be eligible to compete for a Contract for Difference (CfD) in the next auction for less established technologies planned for 2019; and

iii. proceeding with this near-term option for ensuring security of supply on Shetland enables potential further savings to consumers from a joined-up solution, should a transmission link be needed.[5]

1.1.3 Ofgem noted that, further to their decision, they expect that in determining an enduring solution, "at a minimum… GB consumers would be no worse off overall than the [NGSLL]-Aggreko Solution".[6] SHEPD's approach to the current proposal has been focused on meeting this expectation.

1.1.4 SHEPD first outlined a whole system approach with Ofgem in January 2018,[7] setting out the different potential outcomes associated with implementing a passive or proactive attitude towards the ongoing transmission and wider developments on Shetland. We highlighted the possibility of success – an efficient outcome and value to consumers - of a joined-up approach where the DSO acts proactively to procure what it needs from other energy market participants. This is summarised in Figure 1 below.

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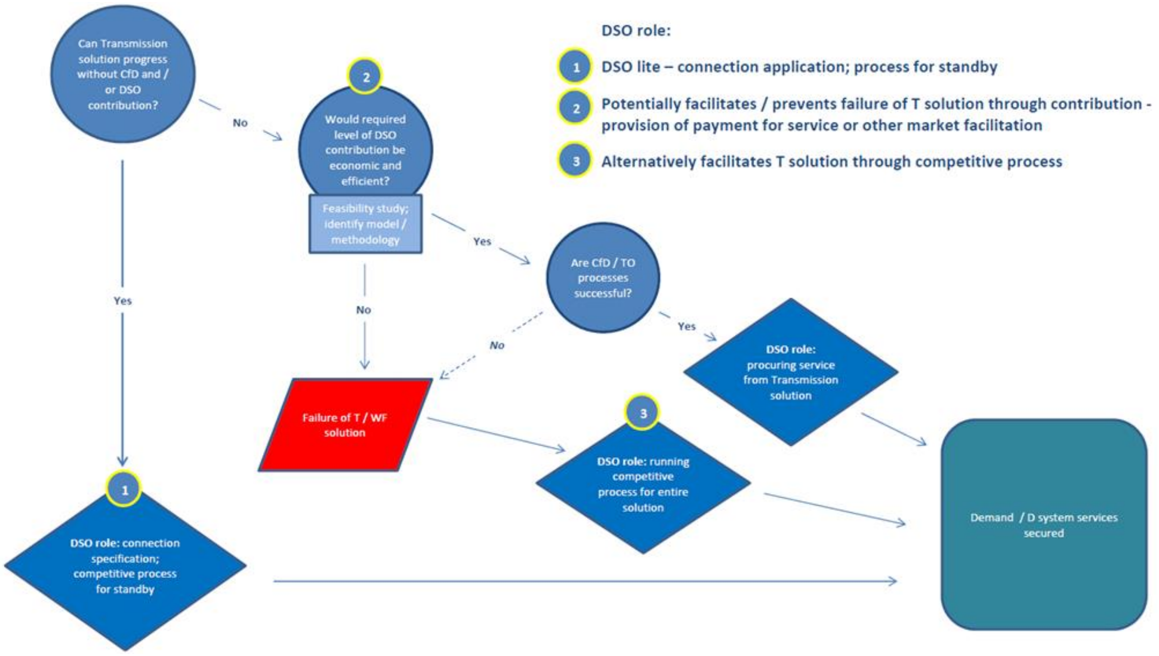
[4] *Ofgem's determination of Scottish Hydro Electric Power Distribution plc's (SHEPD) submission required under Charge Restriction Condition (CRC) 18A*, April 2014
[5] *Decision on Shetland New Energy Solution*, November 2017, p.11
[6] Ibid., p.28
[7] SHEPD presentation, *2018-01-30 Shetland next steps*

**Figure 1: Potential routes for DSO role**




1.1.5 In May 2018 we set out specific work packages driving at identifying whether a transmission solution is the optimum means of meeting Shetland's distribution system needs, what is an efficient contribution, and how that contribution could be made.[8] In July we shared the detailed methodology statement setting out how Baringa would carry out their analysis, and Reckon's overview of how they would determine an appropriate route for making any contribution. In our update in August 2018, we discussed in more detail the potential to realise consumer benefit in the event that a fair contribution could be identified which represents better value than the updated NES cost benchmarks, discussed further below.[9]

1.1.6 We note that Ofgem has shared initial questions on approach, shared by letter and email[10] – we have set out responses to these in **Error! Reference source not found.**.

## 1.2 Consumer benefit

1.2.1 Realising consumer benefit and value is at the core of SHEPD's whole system approach to its recommended enduring solution. This recommendation will realise a reduction in the cost to customers of £**145m**.[11]

1.2.2 In setting out how it intended to identify and assess the alternative options for an enduring solution post NES 2017, SHEPD designed the stages to ensure all viable options were considered, reference costs were up to date and efficient and the benefit to customers was maximised. This approach was

[8] SHEPD presentation, *2018-04-30 Ofgem bilateral Shetland enduring solution May 3 2018*
[9] SHEPD presentation, *2018-08-02 Ofgem bilateral - Shetland enduring solution*.
[10] *Shetland New Energy Solution*, letter from Ofgem to SHEPD, 19 March 2018; 'RE: Shetland Catch Up', email from Ofgem (James Norman) to SHEPD, 15 August 2018
[11] In present value terms.

presented to Ofgem, and other key stakeholders, at various stages of development throughout 2018, as set out above.

1.2.3 This approach is consistent with and informed by Ofgem's Directions in 2014[12] with respect to Shetland and the principles of the RIIO price controls.

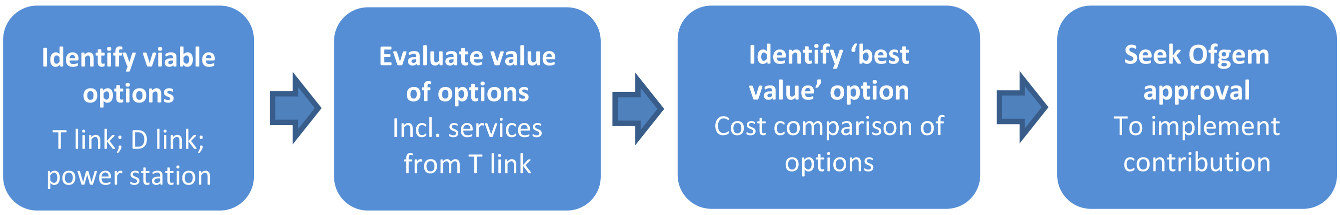
1.2.4 The opportunity to secure consumer benefit is directly related to the licence obligation held by SHEPD, in its capacity as DSO, to identify an enduring security of supply solution for Shetland at the lowest cost for consumers. This places a requirement on SHEPD to identify a security of supply solution within the remaining operational period of the current interim solution. For SHEPD, this means the identification and implementation of a solution by 2025.

1.2.5 Following Ofgem's decision to halt the NES process in November 2017[13] and its 20 March 2018 letter[14] instructing SHEPD to explore options to secure demand for Shetland consumers in conjunction with a proposed Shetland Transmission link, SHEPD has been progressing a number of workstreams to test:

1. whether a transmission-link solution is the best value solution for Shetland consumers;
2. to evaluate the fair value of a DSO contribution to a transmission link; and
3. the mechanism by which such a contribution could be made.

1.2.6 This approach is summarised in Figure 2, below.

**Figure 2: DSO workstream key stages overview**




[12] *Ofgem's determination of Scottish Hydro Electric Power Distribution plc's (SHEPD) submission required under Charge Restriction Condition (CRC) 18A*, April 2014
[13] *Decision on Shetland New Energy Solution*, November 2017
[14] *Shetland New Energy Solution*, letter from Ofgem to SHEPD, 19 March 2018



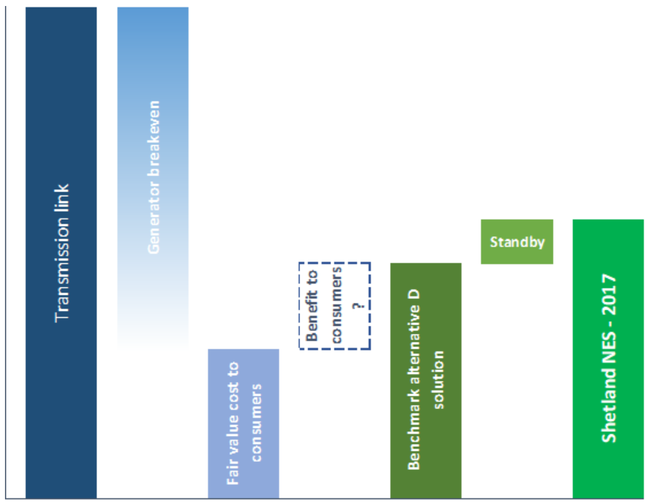


**Amended for publication**

## 1.3 Whole system

1.3.1 SHEPD's approach is based on securing the best value for consumers by considering the opportunity presented by a whole system approach. As a simple illustration of this principle SHEPD has consistently referenced the following diagram:

**Figure 3: Best value, whole system approach**




1.3.2 A whole system approach is aligned with the intent signalled for RIIO2, feedback from stakeholders in the final Shetland NES 2017 consultation responses and ongoing engagement with Ofgem, BEIS and Scottish Government. At its core it employs common sense.

1.3.3 The approach does cause SHEPD and Ofgem to consider new regulatory concepts. SHEPD considers that this is a positive outcome and a valuable test of a potential whole system approach ahead of RIIO2. In order to implement this approach in practice we may require amendments to existing licence arrangements, or potentially small changes to or derogations from industry codes; we consider this as worthwhile in realising material savings for consumers. SHEPD recognises this and considers that the available time post Ofgem's decision on the identified solution and value and prior to energisation will be sufficient to make such changes (see section 5).

1.3.4 Questions over what a fair value of contribution is to an asset with shared purpose will occur again and again during RIIO2 if whole system solutions are promoted. This process on Shetland illustrates some of the challenges in addressing what is fair.

1.3.5 We consider that the approach taken to date is also well aligned with the transition to DSO. The definition and functions of a DSO as set out and consulted upon to date include the following:

- securely operates and develops an active distribution system comprising networks, demand, generation and other flexible distributed energy resources (DER);
- a neutral facilitator of an open and accessible market - it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation;

- enables customers to be both producers and consumers; enabling customer access to networks and markets, customer choice and great customer service.

1.3.6 Reflecting on i) the development of the Northern Isles New Energy Solution (NINES) project, the core elements of the Active Network Management (ANM) system and managed renewable connections continuing as key components in the energy architecture on Shetland, ii) the market-testing undertaken under the NES, and iii) the current whole system approach which seeks to meet Shetland's demand needs at best value, reflecting (and seeking to enhance) the deployment of DER, and enabling access to the GB market, with associated security and low carbon benefits, we consider there is alignment with these principles.

1.3.7 With regard to whole system planning, a key area of focus has been how distribution and transmission companies can work together to identify the best whole system solutions required to deliver their outputs. In the Shetland DSO workstream we have demonstrated a methodology and identified clear value from this whole systems approach.

1.3.8 All this has been done with a passionate focus on maintaining the level of security of supply on the islands, fulfilling another key element of the definition of a DSO.

1.3.9 In summary the approach taken in Shetland is well aligned with the definition of a DSO and in many ways is a number of years ahead of the mainstream developments, creating an opportunity to stress-test the arrangements that will be prevalent in a DSO world, and to do that in an environment that remains distinct from the market distortions brought about by innovation funding.

## 1.4 Robust independent assessment - specialist support

1.4.1 SHEPD has incorporated learning from the Shetland NES process; that the use of external experts and professional advisors demonstrates the integrity of the assessment process. This approach has continued during the current process and we have ensured that the process, consultant terms of reference etc have been shared for review and comment in advance of work commencing. SHEPD understands the potential complexity of this recommendation process in light of the wider relationship SSE plc has with Shetland. SHEPD has and will continue to take steps to demonstrate the integrity of its assessment and recommendation process.

1.4.2 Specialist support has been provided to the DSO workstream in the following ways:

- Baringa has calculated the counterfactual costing and cost estimates and opined on potential alternative valuation models.
- Mott MacDonald has provided technical analysis on the practicality of the technical options considered, plus technical and cost assumptions for the counterfactual analysis.
- Reckon has analysed the contribution methodology and opined on optimisation options and alternative valuation models.
- CMS has provided opinions on the recommendation and the potential impact it has on the obligations and responsibilities of SHEPD and Ofgem.

1.4.3 In-house specialists have provided certain inputs and checks on inputs where appropriate and NGESO has engaged in discussions of the TNUoS charges generators would face.

1.4.4 The specialist advisors have reviewed the calculations used in this recommendation.

1.4.5 With specific reference to the consumer benefit workstream questions set out above; in order to answer these, SHEPD employed consultants Baringa Partners and Mott MacDonald to assess

the updated costs of the proposed 2017 NES solutions (distribution link and standby generation, and full duty power station) as a direct replacement for LPS, i.e. the cost of the next best solutions if a transmission link is not built.

1.4.6 In parallel, contribution modelling consultant (Reckon) was tasked with developing a method by which a contribution could be made. SHEPD's focus in identifying the optimum mechanism has been on the ease and speed of implementation, avoiding the risk of external legal challenge and the requirements and timescales for licence and code changes.

## 1.5 Timescales for action (**d**)

*Identifying an enduring solution*

1.5.1 LPS is approaching the end of its operational life and was expected to exceed previous emissions limits set by the Industrial Emissions Directive (IED) in 2020. The station was unlikely to have met revised IED emissions limits without substantial modification and consequently, was expected to close in 2020, driving the need to find a new energy solution.

1.5.2 Further to the European Commission's July 2017 decision, a time-limited reprieve has been provided for island systems for meeting emissions limits. SHEPD is therefore now targeting a revised date of 2025 for implementation of an enduring solution. Supply from Sullom Voe Terminal (SVT) remains uncertain; the terminal is understood to face similar emissions restrictions to LPS.

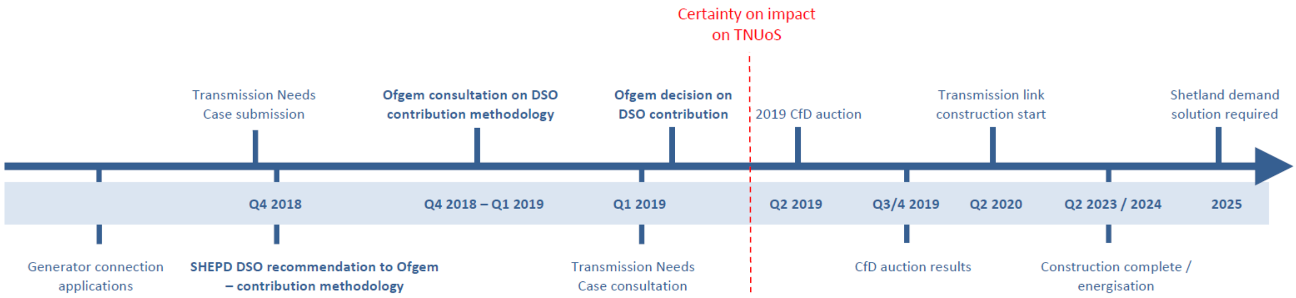
*Time-limited DSO process*

1.5.3 The 2019 CfD auction is expected to open by May 2019, as confirmed by BEIS[15]. In order to maximise the opportunity to achieve the best value outcome for consumers, a decision on a contribution must be reached in adequate time ahead of the auction, with adequate clarity and certainty on implementation, to allow relevant stakeholders (TO, NGESO and generators) to take account of its effect.

1.5.4 SHEPD has set out and discussed with Ofgem a high-level process map (see Table 6: Outline regulatory process) for the progression of the recommendation through review and consultation, with the target of an Ofgem decision by February 2019 (see section 8). We consider that this programme allows adequate time but requires to be met in order to allow relevant pre-CfD implementation steps to be fulfilled ahead of parties bidding in the auction. This process is summarised in Figure 4, below. (**d**)

[15] *Guaranteed clean energy auctions in 2019*, BEIS, 23 July 2018

Figure 4: Indicative forward-looking timeline




## 1.6 Realising opportunity for consumer savings (b)

1.6.1 This DSO workstream has identified a cost to consumers of £249m, offering consumers a one-time opportunity for a whole system solution to deliver material savings of approximately £145m. If the transmission link is not built, it may be reasonably expected that consumers will be exposed to the cost of the next best alternative, which we have calculated, using a methodology developed by Baringa, to be approximately £394m.[16]

1.6.2 Further to analysis by our consultants it is considered not credible that a similar level of savings could be realised from a future competitive process.

[16] SHEPD would note that the value Baringa have calculated does not include the costs of the mid-life refurbishment which the distribution link would have needed to complete at around year 25. Using the recommendations of Mott MacDonald on timing and costs SHEPD have recalculated this value and believe it should be c.£394m and not £376m.

# 2 Stakeholder engagement (c)

*Government*

2.1.1 SHEPD has had engagement with the Energy Directorates at BEIS and the Scottish Government as it has developed these proposals to ensure that these stakeholders have no material concerns with this approach.

2.1.2 The reaction of BEIS' advisors to date has been that it is not its role to comment on a contribution value and associated implementation, noting that this is Ofgem's remit. Its key recommendations are that SHEPD continues to work with Ofgem, in order to provide all that is required to determine a position on the recommendation, given the tight timelines (noting that this has been the case to date), and that SHEPD gives thought to its management and mitigation of conflicts of interest, and clarity of separation, in the context of stakeholder perception.

2.1.3 Scottish Government advisors have not provided detailed feedback to date but note that the concept of a best value, whole system approach is positive. SHEPD understands that briefings are being prepared for the relevant Scottish Government Minister(s).

*Industry*

2.1.4 SHEPD has had engagement with SHE Transmission in order to understand the key metrics and process associated with its Shetland Needs Case. This has included seeking its view on link costs which has been applied to determine the "peak demand support", and further Transmission technical and cost data to enable the assessment. SHEPD will engage further with SHE Transmission over the next phase on the contribution implementation process.

2.1.5 SHEPD has had initial engagement with NGESO in order to understand some of the mechanics of the process by which TNUoS is calculated in order to determine the contribution mechanism approach. This engagement will move into a more detailed phase with NGESO over the recommendation review period in order to test and agree the contribution process fully.

2.1.6 SHEPD will maintain engagement on progress with all of these parties.

2.1.7 SHEPD has not shared recommendation values or the final proposed mechanism with any third parties. (e)

*Stakeholder feedback from 2017 NES process*

2.1.8 Ofgem's consultation on the costs and characteristics of the 2017 NES[17] attracted a number of responses. Given its focus on identifying an enduring solution for the Shetland islands, it is relevant, as we consider our recommendation, to reflect on the stakeholder feedback received and the positive additional benefits stakeholders identified as desirable from a large island link.

2.1.9 8 of the 11 published responses (of 15 total, 4 of which were confidential) were in support of a large transmission link, either as the intended means of meeting Shetland's distribution needs, instead of a separate solution such as a distribution link or full duty islanded power station, or in combination with

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[17] Consultation on the cost of the new energy solution for Shetland, July to August 2017

a distribution link, if a demand solution was required sooner than a transmission solution could be established.

2.1.10 In summary, these respondents favoured a transmission link as the means of being able to maximise the benefits and significant long term economic development opportunities that an optimal "joined-up" and more considered solution could be expected to provide.

2.1.11 The responses reflected on the themes of:

- cost efficiency
- the multiple benefits offered by a transmission solution, to both Shetland and GB
- political commitments to progress wind and mainland link projects to remote islands

2.1.12 The possibility of applying an "avoided cost" consideration towards a transmission solution was also raised.

*Cost efficiency*

2.1.13 Responses reflected the inefficiency of cost of a distribution link compared with a transmission solution, and the potential detriment to public interest which could follow progressing a small-scale link, as a result of failing to exploit renewable resource to local Shetland and wider GB benefit and associated socio-economic upsides.

2.1.14 Respondents compared the distribution link cost, scale and functionality with existing information on the transmission link, noting that the distribution link "looks like an expensive option", "at around half the cost of the proposed 600MW…transmission link, delivering one tenth of the capacity", and "…per MWh more expensive to GB consumers compared to…a Transmission Link". The distribution link was described as an "outlier in terms of capacity, voltage and cost", not being cost efficient compared with other approved or operational commercial link projects.

2.1.15 It was noted that National Grid confirmed in their January 2017 Network Options Assessment report that the Caithness–Shetland 600MW HVDC link was the "most economic, efficient and coordinated option" to allow the "attractive renewables resources" on Shetland to be developed. One respondent reflected on the anticipatory investment in the Caithness-Moray infrastructure associated with enabling import to GB from a Shetland transmission link (£100m), noting that it would fall on consumers rather than Shetland generators if a Shetland link were not to be developed.[18]

2.1.16 Ofgem responded, "We do…note that a large number of respondents highlighted the potential merits of a larger transmission link to Shetland and argued that there should be no decision on the Shetland New Energy Solution until the outcome of the next CfD auction (and the need for a transmission link) is known. We recognise that it is important to have an integrated solution for Shetland. We also note the risk that if we were to approve the NGSLL-Aggreko Solution in 2017 and a transmission link were to come forward in the future and meet security of supply requirements on Shetland, then this outcome may not, with hindsight, offer the optimal cost solution for Shetland and consumers in the long-run."

[18] Reflected in responses from Shetland Islands Council, Shetland Charitable Trust, Viking Energy Shetland, Energy Isles and Element Power.

*Benefits to Shetland and GB*

2.1.17 Responses reflected on the benefits offered by realising a dual function of a transmission solution in both providing a means of exploiting Shetland's excellent renewable resource, and meeting distribution system needs. The responses highlighted the perceived multi-faceted nature of the benefits that a transmission solution could bring to the Shetland islands and also in a wider GB context, compared with an alternative solution. These benefits were noted as including increased deployment of renewables, reduced reliance on fossil fuels, contribution towards the GB energy mix and energy security, and significant and long-lasting local economic development.

2.1.18 A transmission solution was reflected on by a number of respondents as bringing "an economic transformation of the local economy" associated with "the deployment of large-scale renewables on the Scottish islands [which] remains a key strategic outcome for the Scottish Government". Respondents set out that "…an optimal energy solution for Shetland, is one that both meets requirements and enables Shetland to realise its full economic and social potential through advancing renewable energy deployment".

2.1.19 Respondents noted that "island wind offers the UK significant advantages, particularly in respect of contribution towards GB energy security and economic benefit", and that "…a joined up approach to the energy supply option and export potential of renewables from Shetland would provide a more cost efficient solution in any cable option and not only save the UK consumer money but stimulate economic growth in Shetland and the North of Scotland."[19]

*Political commitment*

2.1.20 Several respondents reflected on the UK Government May 2017 manifesto commitment to the "development of wind projects on the remote islands of Scotland, where they will directly benefit local communities".[20]

*"Avoided cost" approach*

2.1.21 One of the respondents suggested the application of the NES cost value towards a transmission solution, noting, "If the incentives identified for the recommended NES project were applied to an alternative transmission connection then that would have a material impact on the charging regime for that link, which in turn would have a material impact on the cost of energy produced from projects in Shetland that might export energy to the UK transmission system while still providing the supply to Shetland consumers required. The scale of potential generation is at least an order of magnitude greater than that pertaining to the NES and so would bring benefit to many more UK consumers for the same cost."[21]

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[19] Reflected in responses from the Scottish Government, Highlands and Islands Enterprise, Shetland Islands Council, Shetland Charitable Trust, Viking Energy Shetland and Element Power.
[20] Reflected in responses from the Scottish Government, Energy Isles and Shetland Islands Council.
[21] Shetland Aerogenerators response

# 3 Contribution valuation data

## 3.1 Introduction

3.1.1 SHEPD, and its advisors, have completed analysis in order to identify (a) the value of the benchmark alternative solution and (b) the fair value of the services and benefits provided by the transmission link connection. Provided the fair value is less than the value of the benchmark then a contribution to the cost of the transmission link is justified as being in the in the interests of consumers.

3.1.2 The benchmark alternative solution has been undertaken by Baringa using a valuation of the costs of the next best option to the transmission link (the costs which would be avoided if the transmission link is built) and SHEPD have valued the link in terms of the services it would provide to consumers. These two approaches and the calculations are independent of each other.

3.1.3 This chapter explains the sources of the data inputs used in the evaluations and the methodologies adopted in order to assist the recommendation review by Ofgem.

### Stage 1 – Identifying the "next best option" for Shetland

3.1.4 Baringa has been engaged to identify the best solution for consumers by comparing the transmission link option against the "next best option" for Shetland as identified by the 2017 NES process, where some of the costs of 2017 NES options are updated to account for more recent market data. This has the advantage of using market tested costs for the counterfactuals making it consistent with market derived costs for the transmission link.

3.1.5 Baringa's approach to identifying the most beneficial solution to meeting Shetland's needs is composed of two main stages:

- *Updating and re-evaluating the 2017 NES options to identify the "next best option":* Using updated modelling inputs, Baringa's in-house optimisation model identifies the best 2017 NES solution, i.e. the 2017 NES option that minimises the cost of meeting Shetland demand for consumers. This may include benefits to consumers in terms of lower cost of curtailing island generation due to added export capability.
- *Comparison of transmission link and the best 2017 NES option:* The best 2017 NES option and the transmission link are compared on a Net Present Value ('NPV') basis to identify the most beneficial solution for consumers. If the transmission link is considered the best available option, the comparison with the best 2017 NES option will inform the range within which any DSO contribution may fall, where the upper bound is the amount that would make consumers indifferent between the best 2017 NES option and the transmission link option.

*Identifying the base assumptions*

3.1.6 The Baringa analysis is based on the market-tested costs provided by the 2017 NES tender process. The details of these costs are commercially sensitive, provided in confidence for the sole use of that procurement process, and so cannot be used in this workstream. It was concluded therefore, that only the headline costs published by Ofgem in the consultation document of July 2017 could be used. The costs published by Ofgem are set out in Table 2 below:

**Table 2: Overall view of capex costs**[22]

| NES cost element | Cost (£m) |
|---|---|
| NGSLL capex costs | 278.6 |
| Aggreko capex costs | 24.6 |
| Total | 303.2 |

3.1.7 Baringa assumed a 3.5% real discount rate and that annual costs and revenues would be incurred at the end of each calendar year. As a result, the total costs per annum over the 20 years would be circa. £40m, which would constitute circa. £39m of Availability payments and circa. £1m of Output/Utilisation payments.[23]

3.1.8 The Availability payments represent the true avoided costs of not contracting for the distribution link and standby power station. However, there are two problems with using this cost stream:

- The contractual structure and risk profile for NGSLL as owner and operator of the distribution link tendered under the 2017 NES process was materially riskier than for the construction and operation of the Shetland transmission link by a regulated business. SHEPD expect that the Availability payments include contingency and rates of return in excess of those which SHE Transmission would use for a regulated business project. Certain adjustments can be made to take account of these higher risks in determining the exposure to additional fuel costs and reduced Availability payments using an estimate of the transmission link availability provided by Mott MacDonald.
- The 2017 NES contract, and the Availability payments, were to last 20 years only but the asset has a life in excess of this. If the Availability payments are to be used in the calculation of a value to consumers for year 21 and onwards, assumptions on the operating cost would be required. Mott MacDonald has produced estimates of costs if such a link were to be operated as a regulated business post the end of the 20 year Availability contract period.

*Updating the cost values*

3.1.9 The costs (capital, utilisation and availability) date from the tender submission date of December 2016. This introduces the risk that they are out of date and potentially need to be updated.

3.1.10 Based on the opinion of Mott MacDonald and market tested SHEPD internal data for similar equipment, SHEPD concluded that the 2017 NES costs were still valid.

3.1.11 No operation and maintenance (O&M) costs were published by Ofgem in its 2017 NES consultation, therefore Mott MacDonald has also made estimates of the O&M costs plus any mid-life refurbishments required to extend the life to a 45[24] year evaluation period as used by Baringa.

3.1.12 Mott MacDonald has evaluated the offers received under the 2017 NES process and is of the opinion that the distribution link and standby power station remain efficient offers, and that no material improvements are available. However, Mott MacDonald is of the opinion that a lower cost on-island power station is theoretically possible and have undertaken an optimisation and approximate costing exercise (using the same minimal functional specification used in the 2017 NES). The main ways to

[22] *Consultation on the cost of the new energy solution for Shetland*, Ofgem, July to August 2017, p.20
[23] *Ibid*., p.21
[24] An HVDC link is considered to have an economic asset life of 45 years.

reduce costs would be through changes in the following:

- Reduced civil engineering costs by revising the site at the cost of increased visual intrusion and impacts.
- Smaller engine sizes to reduce the part load running of an engine therefore increasing the average efficiency.
- Smaller engine sizes and the use of a battery to reduce the constraints on the existing distribution connected wind farms thus reducing the fuel cost.
- The use of lower cost fuels.

3.1.13 Applying the cost reduction benefits associated with these changes assume the ability of SHEPD to specify them as requirements within a future tender.[25]

3.1.14 Mott MacDonald has undertaken an optimisation of the engine sizes using data on embedded wind generation, a significant storage device and the demand profile for Shetland, and determined that a plant with ~5MW engines is the central optimisation supported by a limited number of small high speed engines as fast start and low cost peaking capacity.

3.1.15 Mott MacDonald has identified that the costs of sulphur abatement equipment is prohibitive for a power station of this size, ruling out low cost heavy fuel oils as a fuel.

3.1.16 Due to the size and duty of the power station, the widely available low sulphur liquid fuel (e.g. 0.1% sulphur gas oil or marine diesel) was determined to be the liquid fuel of choice for the plant. In addition the use of Liquified Natural Gas (LNG) as a fuel was investigated. Small scale LNG fuel routes are being developed to serve ports in Northern Europe predominantly as a replacement for bunker fuel but also for small land based applications. No such small scale facility currently exists in GB but other European countries have developed (or are developing) small scale LNG facilities.

3.1.17 It is likely that small scale use of LNG will be developed in the UK in the coming years but the lack of construction experience and a liquid market in LNG makes it very difficult to identify prices for LNG delivered to Shetland which could be relied upon.

3.1.18 SHEPD have undertaken an LNG pricing exercise using in house specialist skills supported by Baringa and Mott MacDonald. The central estimate suggests that LNG would be a slightly cheaper fuel than low sulphur liquid fuel (before infrastructure development costs are considered) but the margin for error is too large for this to be a definitive conclusion without a more detailed study. The price advantage of LNG over liquid fuels is insufficient to displace the distribution link as the counterfactual.

3.1.19 It should be noted that an outlier option is the use of natural gas from Total's facility on the island which currently processes gas from the Laggan-Tormore offshore gas field before it is exported to GB mainland. This facility has no infrastructure to provide gas for this use. If these hurdles were overcome it is likely that, even allowing for the cost of a gas pipe to Lerwick, a power station burning Shetland gas would be substantially cheaper than an LNG fuelled facility.

[25] SHEPD did not make such specifications in the 2017 NES tender, further to the requirement to ensure the tender was technology agnostic and as open to as wider a field of bidders as possible.

3.1.20 As discussed above, it has therefore been assumed that the 2017 NES cost for the distribution link remains a valid benchmark. A lower cost on-island power station has been developed by Mott MacDonald and included in the evaluation in order to ensure that the lowest possible cost counterfactual has been used in the calculation of the avoided costs.

*Sensitivity analysis*

3.1.21 Baringa undertook sensitivity analysis around the central cases to reflect uncertainty related to costs of different solutions and wider energy market conditions, including different commodity price scenarios published by BEIS.

3.1.22 Baringa's analysis used their Market Dispatch Model (MDM), an optimisation model which minimises generation costs given a number of input assumptions on fuel prices, power station characteristics, costs, and demand patterns.[26] The MDM was run with updated inputs in light of evolutions in market conditions and in the Shetland power system since the 2017 NES analysis.

3.1.23 Three main commodity scenarios were modelled using values published by BEIS (Low, Central and High). A further scenario was modelled which considered the possibility of significant new industrial demand of 9MW.

3.1.24 Using outputs from the MDM, the supply options were compared using their respective costs and benefits for consumers under the different scenarios. The total cost of each solution is captured into the analysis:

- CAPEX is reflected on an annuity basis, to ensure that options with different economic lives are compared on a like-for-like basis and options that have a longer economic life as well as a higher total cost are not unfairly disadvantaged;
- Operations and maintenance costs were provided by Mott MacDonald;
- Costs of power imports from GB include the cost of electricity from the mainland and of losses, valued at GB power prices as estimated by Baringa;
- Plant utilisation costs include fuel and carbon prices are taken from the relevant BEIS price scenario;
- Cost of testing fuel corresponds to the cost of the fuel burnt when exercising27 the standby power station in the case of an HVDC link (note this is only relevant to comparisons with on island generation options, as the value will be the same for different types of links);
- Other generation costs correspond to the running costs of existing wind in order to meet Shetland demand; and
- Renewable generation curtailment is valued at the cost of additional generation that is brought in to cover the energy gap from any curtailment action.[28]

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[26] The MDM also uses input wholesale power prices for GB, which are determined from Baringa's GB Power Model. In the case of the distribution link, all energy is valued at the GB wholesale price (on an hourly basis).
[27] Periodic operation required to make sure the standby power station can be operated at short notice.
[28] Also note that the following factors have not been considered in the commercial evaluation: spinning reserve; network issues and associated costs; costs associated with enabling future wind on Shetland; and interconnection to Norway.

*Final steps in calculating the values*

3.1.25 Given that different 2017 NES options differ in the timing of associated benefits and costs, the benchmarking is undertaken on an NPV basis. This ensures that differences in the costs and benefits between different options, and the timing of their accrual, are evaluated on a consistent basis. The rate used to discount any costs and benefit is 3.5% in real terms, as recommended by government in the Green Book guidance on project appraisal (Social Time Preference Rate (STPR)).[29]

3.1.26 The value of the costs for the distribution link exclude the costs of a standby power station to support the distribution system during link outages as the standby power station is common to the proposed transmission HVDC link scenario. Additional DSO costs have been included to cover the capital cost of connecting the distribution system to the new transmission system via a new GSP. As with the cost of the standby power station, the cost of integrating the supply from a GSP into the distribution system and replacing the distribution control system which is located at LPS, and the cost of the ongoing operation of the distribution system (currently included within the operational costs of LPS) are common to both the distribution and transmission link.

*Summary of Stage 1 steps followed:*

- market testing of prices offered under a recent tender (also evaluated and published by Ofgem in minded-to position to approve);
- the continuing validity of pricing has been checked by independent consultants;
- where necessary costs have been updated to current day, and gaps in the pricing have been filled using independent advice;
- the calculation of the benchmark has been completed by Baringa.

## Stage 2 - Comparison of the transmission link with the best NES option

3.1.27 The inputs to the evaluation of the transmission link used costs and performance data supplied by SHE Transmission using data consistent with the Needs Case for the link. They were reviewed by Mott MacDonald. Where there were differences of opinion the more conservative assumptions were used to avoid inflating the avoided cost. Baringa have modelled the performance of the transmission link including the additional sections of the Caithness-Moray link to which it will connect, i.e. the losses and availability assumptions cover the whole link from the 132kV alternating current connection at the Kergord converter station to the alternating current connection at the Blackhillock converter station.

3.1.28 Baringa used their MDM to model the Shetland electricity system in the case a transmission link is built and Shetland-based wind capacity is delivered in the upcoming CfD auction. The range of scenarios evaluated included Low/Central/High commodity prices, High additional industrial demand, and different combinations of wind farms being built on Shetland. For each modelled scenario the cost of meeting Shetland's electricity needs using the transmission link option was calculated.

3.1.29 Baringa then completed a cost and benefits analysis for the transmission link using the same methodology as for the 2017 NES options. The only notable difference between the approaches for 2017 NES options and the transmission link relates to the corresponding CAPEX values. In the case of the 2017 NES evaluation, CAPEX values were used as described above. The transmission link CAPEX

[29] HM Treasury (2018), *The Green Book – Central government guidance on appraisal and evaluation*

treatment is different, because the transmission link would be shared between Shetland large transmission connected wind generators and Shetland demand. More specifically, the link would be used to export to GB mainland most of the time, but would also enable power imports into Shetland, when Shetland wind generation is too low to serve demand. Because the share of transmission link CAPEX covered by developers is borne by private parties, Baringa determined that any DSO contribution is the only portion of the overall transmission link CAPEX which has a welfare impact on consumers. Therefore, Baringa modelled the transmission link CAPEX in the CBA as the value of any DSO contribution to the costs of the transmission link. This is the value which balances the CBA between a transmission link and the next best Shetland solution, and is the price that consumers would be prepared to pay for a transmission link connecting to the distribution system on Shetland.

3.1.30 To account for differences in accrual of costs and benefits between the transmission link and the distribution link options, the final costs and benefits are calculated on an NPV basis. The preferred solution is the option with the highest balance of costs and benefits for consumers and Baringa have calculated the DSO contribution level where consumers are indifferent to which of the two links are built.

*Summary of Stage 2 steps followed:*

- the same CBA approach as used to identify the "next best option" for Shetland, including scenarios;
- the inputs used for the transmission link part of the CBA are consistent with the transmission link Needs Case;
- all inputs were reviewed by an independent specialist advisor and the most conservative value used to avoid inflating any contribution calculated;
- the whole of the transmission link was considered including the sections of the Caithness-Moray link it will utilise;
- the calculation of the benchmark has been completed by Baringa;
- the benchmark calculated covers the whole life of the transmission link, as is the price consumers would be prepared to pay for the transmission link if it was used to supply them.

3.1.31 We have provided all methodology statements, reports and results to Ofgem as part of our submission.

## 3.2 Alternative fair value tests

3.2.1 SHEPD have conducted additional analysis supported by CMS, Reckon and Baringa to investigate alternative mechanisms for establishing a fair value contribution based on the support a transmission link provides to the distribution system. This analysis does not use avoided costs of alternative solutions, but seeks to quantify the benefits a link would provide to the distribution system on Shetland. For the areas of support delivered there are no existing GB market valuation mechanisms for this support so SHEPD has developed the following bespoke valuation mechanisms.

- Control support, due to the highly effective control of the distribution system provided by an HVDC link converter station.
- Capacity support, as the link provides the instantaneous ability to satisfy any practical future Shetland demand at all times and at no notice.
- Reduction in losses, achieved because the proposed transmission link operates at a higher voltage than the link proposed in the 2017 NES process.

3.2.2 SHEPD would note that this is an alternative valuation mechanism being applied to Shetland, and that no elements are additive to the DSO avoided cost, as the counterfactual in the avoided cost analysis (the 2017 NES HVDC link) would provide almost all the services offered by the proposed transmission link evaluated in this approach. SHEPD note that Baringa have undertaken a valuation of the losses reduction in their counterfactual, but this is a different losses valuation from the one included here.

*Control support*

3.2.3 When in service the HVDC converter at Kergord (which is part of the transmission link) will be capable of providing services which would manage the stability of the distribution system regardless of the generation mix connected to the distribution system. This is a significant increase in functionality over the current system where the combination of LPS, supplies from SVT and the ANM system are currently able to allow only 22% intermittent renewables onto the distribution system whilst maintaining system integrity. The link will provide instantaneous balancing services for 100% of demand which is a service the GB electricity market does not currently value. Therefore, an alternative valuation mechanism is required. This control capability is required for a large expansion of renewable generation to supply distribution customers. The improved functionality provided by the converter station could be considered to provide an additional carbon reduction in excess of that being procured through the CfD process. Two different methods have been used to value this special carbon reduction.

i. *The link provides balancing services only (inertia[30], frequency and voltage management) - no net energy flows into the distribution system from the transmission system*

3.2.4 In this valuation mechanism a theoretical model is constructed which combines the control capability of the converter station with the energy production of a liquid fuel power station and the greatest possible renewable energy penetration. To determine the highest level of renewables penetration on a current system, the target of the System Operator Northern Ireland (SONI) of 75% renewable energy penetration on to its grid system[31] has been used. The value of the reduction in carbon emissions from changing to a system powered with 75% on-island renewable energy has been calculated using the BEIS forecasts for carbon prices. Shetland carbon intensity has been calculated based on the assumption of a high efficiency gas oil fired power station supplemented by distribution-connected windfarms at the current level of renewable penetration of approximately 22% (analysis suggests that there is little scope for additional wind capacity on Shetland when balancing services are provided by a power station). The Shetland carbon intensity in 2024 (when the link would commence operations) is estimated to be

[30] Inertia cannot be valued directly as GB has no inertia pricing mechanism. The EFR is the closest although it does not recognise the unlimited duration of the support from the link compared to the EFR participants can provide support and therefore using these values would underestimate the value of the link service.
[31] http://www.soni.ltd.uk/newsroom/press-releases/soni-renewable-energy-rec/ NB: This is a peak power target not an energy target but for the purposes of this analysis it is assumed to be an energy delivery target.

460g$CO_2$/kWh, which reduce to a carbon intensity of 150g$CO_2$/kWh with 75% renewables.

*ii. The link provides energy and reduces Shetland distribution system carbon intensity to that of GB*

3.2.5 The control capability of the converter station will allow the higher carbon on-island thermal generation to be shut down most of the time, with electricity being supplied either from renewable sources on Shetland or by lower carbon electricity from mainland GB. Carbon based fuels would be used only when the link is out of service. Using the BEIS forecasts for carbon price, and mainland GB electricity carbon intensity which fall from 103g$CO_2$/kWh in 2024 to 63g$CO_2$/kWh by 2035[32] it is possible to calculate the value of the reduction in carbon emissions. As set out above, Shetland carbon intensity has been calculated based on the assumption of a high efficiency gas oil fired power station supplemented by distribution connected windfarms at the current level of renewable penetration of approximately 22% (analysis suggests that there is little scope for additional wind capacity on Shetland when balancing services are provided by a power station).

3.2.6 It should be noted that the 75% renewables penetration scenario saving takes no account of the economics of such a level of renewables on Shetland where the technology required to achieve 75% penetration may not be economically viable. Therefore, this mechanism for calculating the contribution has been discarded and the value ascribed to the control functionality is that associated with achieving GB carbon intensity. This value is calculated using a similar mechanism to that used by Baringa to calculate the benchmark value i.e. the value is the capital sum which would produce a 45 year annuity where the first 20 years of the annuity would balance the 20 year CBA.

*Capacity support*

3.2.7 The link provides approximately twelve times the capacity required to satisfy Shetland demand. This capacity is immediately available at no notice (assuming the link is in service) which is an effective long term guarantee of the ability to satisfy Shetland peak power demand. Even though this supply would be provided at all times the link is energised, there are particular times of support when the link provides power to distribution consumers because there is insufficient renewable energy being generated on Shetland. There are a number of ways of valuing such a supply. The following have been considered:

- Peak Shetland power demand as a percentage of the link rating.
- Shetland energy demand as a percentage of the expected maximum export via the link.
- Peak Shetland power demand as a percentage of the rating of the anchor project (the smallest proposed project necessary for the jink to be justified - currently the Viking Energy Project).
- Shetland energy demand as a percentage of the expected maximum export from the anchor project.

[32] These forecasts run to 2035 only, so for all years post-2035 the values are considered to remain at the 2035 value.

- Percentage of the year where the link exports to GB are less than Shetland peak power demand, i.e. the amount of the year when the link guarantees that Shetland peak power demand can be satisfied.

3.2.8 This analysis has been carried out using data provided by the SHE Transmission team or data which is publicly available.

3.2.9 It is noted that the distribution connection does not drive any change in specification pf the transmission link.

3.2.10 The options in the analysis which compare Shetland demand to the rating or export flows of the link do not take account of the ability of the link to instantaneously satisfy Shetland demand at any time and at no notice. The most appropriate mechanism is considered to be the percentage of the time that the link could be required to import energy to satisfy Shetland peak power demand, at 17.4%, and that the value the link provides to distribution consumers is 17.4% of the project capital cost.

3.2.11 It should be noted that the demand forecast used for this analysis was agreed with Ofgem for the 2017 NES process and covers the period 2015 to 2040. It takes account of a low level of demand side management and energy efficiency measures. The values used are the central case for the year 2025 and were the values tenderers to the 2017 NES process were told to assume.

3.2.12 The standby power station would be unable to provide automatic and immediate capacity support to distribution consumers in response to an unpredictable drop in wind generation unless it was operational at the time and ready to replace any lost generation. Therefore, it does not provide the same capacity service as the link and so cannot been used in this type of valuation.

*Losses*

3.2.13 The proposed transmission link will deliver electricity to Shetland with lower losses per unit of energy transmitted than the 2017 NES link, because it operates at a higher voltage of +/-320Kv compared to the proposed 2017 NES distribution link which was to have operated at +/-88kV. Cable losses per km are inversely proportional to the square of the voltage.

3.2.14 In practical operation some of the energy generated by the transmission connected windfarms will be diverted to the distribution system and not exported to mainland GB. This netting off effect reduces the electrical losses on the HVDC link. However, this in effect increases the export capability of the link for the same level of electrical loss.

3.2.15 The alternative way to consider the losses is to consider the proposed transmission link as two different notional links, one solely for exporting wind generation to GB and rated at 600MW, and a second link which is solely for supplying demand consumers on Shetland and rated at the Shetland demand. The losses from second "demand" link can be compared with the losses for the 2017 NES distribution link for the same Shetland demand scenarios.

3.2.16 As part of our analysis, we considered the 2017 NES tender submission estimation of the cable losses on the proposed distribution link. The ratio of losses for the two links will be $(320/88)^2 = 13.2$ for a given cable resistance. Based on this ratio, and assuming that the resistance of both links are the same, the differential can be calculated for an energy flow and valued using the BEIS projection of wholesale power prices (assumed to remain constant when the forecast ends in 2035).

3.2.17 In addition to the cable losses the converter stations cause electrical losses. Mott MacDonald are of the opinion that the losses for a +/-88kV converter station only supplying Shetland demand and a +/-320kV converter station supplying the same demand profile would be approximately the same. Therefore, no further loss credit is claimed beyond the reduced cable loss.

3.2.18 Mott MacDonald also noted that in a practical application the smallest commercially available cable for a +/-320kV link is significantly larger than that required for power flows of up to 50MW. A larger cable would reduce the resistance of the link and so reduce the cable losses even further. Mott MacDonald estimate that the larger cable size would further reduce losses by a factor of 2.67 making the losses on a practical +/-320kV system 1/35.4 of the losses on a practical +/-88kV link. However, this additional losses reduction is only available if the whole transmission link is considered to supply distribution consumers and not the smallest part of the link necessary to satisfy demand. Therefore to be conservative SHEPD have not included this additional loss credit in the valuation.

3.2.19 This value is calculated using a similar mechanism to that used by Baringa to calculate the benchmark value i.e. the value is the capital sum which would produce a 45 year annuity where the first 20 years of the annuity would balance the 20 year CBA.

*Summary of approach*

- The fair value has been calculated by valuing the services an HVDC link brings to the consumers of Shetland;
- The services are: improved control of the distribution network allowing a one-off reduction in the emissions of carbon from electricity supply; reduced losses on the import of electricity from GB; And instantaneous and automatic capacity support;
- The valuation follows a similar methodology to that used by Baringa for the benchmark; and
- The values calculated for the services (losses and control) take account of the availability of the transmission link.

# 4 Security of supply options considered

## 4.1 Description of the options evaluated

4.1.1 The first step in exploring whether the enduring solution for Shetland can be met by a transmission link is to identify and then evaluate the viable technical options and associated costs. Comparison of these options would then permit SHEPD to determine which was the best value option to meet the security of supply requirements.

4.1.2 Recommended option: The option under consideration is a new Grid Supply Point (GSP) which connects the existing Shetland distribution system to a new 132kV transmission network on Shetland which is connected by an HVDC link to GB via the existing Caithness-Moray HVDC link. New large windfarms on Shetland would be connected to the new transmission system to maintain separation of large generation from a small distribution network.

4.1.3 Alternative options were evaluated:

- Distribution link – the most recent counterfactual
- Full service on-island power station (liquid fuel)
- Full service on-island power station (LNG)

## 4.2 Security of supply for Shetland

4.2.1 In the case where an HVDC link is the main supply option, security of supply for customers will be provided by a standby power station connected to the distribution system which would allow the distribution system (supplied by the standby power station and small renewable generators) to run separately from the transmission system in the event of a fault or planned outage on the HVDC link. The security of supply is not dependent on the reliability or performance of the link in any way. If an on-island power station is the main supply option, security of supply is provided by the inclusion of additional generators (N+2) and redundancy in the design. The type of fuel burned will not materially affect the security of supply provided sufficient fuel storage is maintained.

4.2.2 As part of the 2017 NES process, WSP undertook security of supply modelling of all Lot 1 tenders. WSP concluded that either a power station with two spare engines (N+2), or the distribution link combined with a 54.4MW standby power station, would each deliver a Loss of Load Expectation (LoLE) of less than 3.[33]

4.2.3 Given the very similar technical natures of the distribution link and transmission link, and the support of a robust standby power station, it is considered that the WSP evaluation of the LoLE value for Shetland, carried out as part of the 2017 NES process, is still valid. Therefore, if the demand forecast remains relevant, a 54.4MW Aggreko type standby power station or the Mott MacDonald optimised on-island power station (because it includes N+2 engines) will also deliver a LoLE of less than 3. The LNG power station considered is dual fuel as it can burn gas and also liquid fuel, as LNG is expensive to store

[33] The requirement for solutions to meet a LoLE of 3 or lower was the standard agreed with Ofgem for the purpose of the 2017 tender specification.

in large volumes[34]. No further detailed modelling has been completed.

4.2.4 It is interesting to note that an HVDC link will provide a lower system reliability than an on-island power station as any forced outage on the link would likely result in a complete outage, causing a black out of the supply to Shetland. A forced outage at a power station would be highly unlikely to result in a complete shutdown due to the operational reserve and the redundancy and resilience built into its systems. However it is not economic to build redundancy into the main elements of a long distance subsea link.

4.2.5 The standby power station would provide a reliable back-up and enable the DSO to meet its obligations under Engineering Recommendation P2/6. (**f**) The design of the standby power station proposed in the 2017 NES process is therefore considered to be an appropriate and consistent benchmark for the purpose of analysis alongside the transmission link.

4.2.6 Should the conditions of the transmission link Needs Case be met, and construction commences following the results of the CfD auction process according to current published timescales, there will be sufficient time for SHEPD to plan and implement complementary standby arrangements prior to energisation of the link. SHEPD will make a submission for associated standby arrangement allowances following confirmation of the transmission link Needs Case.

4.2.7 In the event the transmission link does not proceed, SHEPD has identified that there would be sufficient time to plan and implement a new enduring solution (assuming a cost benchmark of £394m) before the agreed end date for generation from LPS in 2025 (assuming this process commences following the CfD announcement in 2019, with no delays).

## 4.3 Demand forecast

4.3.1 As part of the 2017 NES process, WSP completed a demand forecast for Shetland in 2016 (energy and peak demand). This demand forecast was agreed with Ofgem and used for the 2017 NES process. SHEPD has not undertaken a refresh of this demand forecast as there is currently insufficient new data to justify such a revision, the scale of moderate demand increases on Shetland does not materially affect the cost of the counterfactuals used in the study, and changes in the forecast peak power demand for Shetland would not affect the rating of the proposed transmission link.

4.3.2 The two areas where a demand forecast may affect the process would be:

- Rating of the GSP used to supply Shetland demand
- Rating of the standby generation facility

4.3.3 The rating of the GSP used for the calculation of the counterfactual is N+1 at 90MVA. This value was used as it is robust to any credible Shetland power demand and because using a higher rated GSP reduces the avoided cost of the transmission link and so does not inflate the potential contribution.

4.3.4 It should also be noted that there is potential for material additional industrial demand on the island following the connection of any transmission link. Depending upon the level of reliability required, this demand may be supplied via a separate GSP. Each large windfarm connected to the transmission link

[34] The 2017 NES process required a storage capacity of 30 days operation and this is felt to be more economic and robust if part of that storage capacity is liquid fuel.

will require a connection to provide auxiliary power when the windfarm is not generating electricity. It is estimated that this could total 7MW if 600MW of transmission connected wind capacity is built. It is not yet known if this demand would be met from the distribution system or the transmission system that would be built on Shetland to export power to the Kergord converter station. The Baringa evaluation includes a scenario of an additional 9MW of industrial demand to test if the Shetland demand affects the contribution.

## 4.4 Technical opinion on recommended transmission link supporting distribution system

4.4.1 Mott MacDonald has concluded that this solution is technically similar to the distribution link which was proposed by the 2017 NES process. It is considered adequately similar, to the extent that much of the modelling and planning work of that process has been reused in assessing the feasibility of this supply option (detailed engineering of the integration of the scheme would be carried out if to the solution proceeds).

4.4.2 The proposed Shetland transmission link and the 2017 NES distribution link offer very similar levels of reliability and planned maintenance periods. However, this evaluation has used conservative estimates provided by Mott MacDonald for the availability of the transmission link which is approximately 0.8% points lower than was proposed for the distribution link in the 2017 NES process. Also included in this evaluation was the impact of the outage periods for the Caithness-Moray link to which the Shetland link will connect.

4.4.3 A back up standby power station would also be required to provide energy and balancing services for distribution consumers when the HVDC link is out of service.

## 4.5 Assumptions on the standby power station

4.5.1 The role of the standby power station to support an HVDC link is to provide security of supply to demand consumers; it therefore requires the following capabilities:

- A connection to the SHEPD distribution system;
- High reliability (low forced outage rate and high start reliability);
- A fast start capability to allow SHEPD to comply with the requirements of ER P2/6 following any HVDC link outage;
- Be capable of prolonged operation to support Shetland if there is a long outage on the HVDC link;
- Include sufficient redundancy and resilience (e.g. segregation of equipment such that a fire cannot affect more than a small portion of the plant);
- Be capable of long term standby operation in the ambient conditions (wind and salt air);
- Be capable of supporting an island network with intermittent generators and be resilient to a series of credible fault scenarios;
- Be capable of compliance with licencing and permitting conditions;

- Operate using a widely available fuel that can be stored for prolonged periods and in sufficient quantities to support the island for 30 days (this storage requirement favours light liquid fuels such as gas oil).

4.5.2 The connection of the Shetland distribution system to a new 132kV transmission system and a HVDC link primarily designed to export up to 600MW of wind power could affect what is required from any standby power station.

4.5.3 It should be noted that there are existing generators on Shetland which could provide some or all of the standby needs of the distribution system. It is not currently known whether reusing existing assets or building new assets is the lower cost option but, to avoid inflating any DSO contribution, the higher cost option of a completely new standby power station has been assumed.

4.5.4 Typically standby power stations such as this can be constructed relatively quickly meaning that the development of a standby power station can be left until after any HVDC link to Shetland is given the go ahead.

## 4.6 WSP static and dynamic stability modelling

4.6.1 WSP undertook static and dynamic modelling of the performance of the distribution link, standby power station and the on-island power station offered in the 2017 NES tenders. This modelling looked at the stability of the 33kV system following certain agreed fault and disturbance conditions. Each of the three elements of the proposed solutions delivered acceptable responses to these fault conditions, although some required small scale load shedding to restore stability following major loss of generation events. SHEPD accepted this analysis as demonstrating that all tendered Lot 1 solutions could be used to operate a compliant and stable distribution system. However, investment in more automated control systems and reworking of elements of the existing protection and control process would be required in the event that an HVDC link was the primary supply option. This cost has been taken account of in the calculation of the counterfactual.

4.6.2 The transmission link converter station will utilise similar technology to that proposed for the 2017 NES process distribution link and will provide a fault current in excess of the minimum necessary calculated during the 2017 NES evaluation. A similar standby power station to that offered under the NES would be likely to be proposed in future; therefore no additional static and dynamic modelling is necessary at this stage as it is expected that the results would show approximately the same results.

# 5 Evaluating cost of options

## 5.1 Updating the 2017 NES costs – competitively tendered

5.1.1 As set out in section 3, the counterfactual costs used were based on the market-tested costs provided by the 2017 NES tender process.

Further to analysis by our consultants, it has been determined that, further to testing these values, the 2017 NES cost for the distribution link remains a valid benchmark. A lower cost on-island power station has been included in the evaluation in order to ensure that the lowest possible cost counterfactual has been used in the calculation of the avoided costs.

## 5.2 Deriving avoided cost benchmark

5.2.1 In analysing the updated the 2017 NES cost benchmarks, consultants Baringa Partners has identified that the cost to provide a Distribution link in today's money (Net Present Value) would be £394m.

5.2.2 In updating and evaluating the 2017 NES options and the transmission link, Baringa determined that:

1. An on-island generation option (full service on island power) provides the least favourable balance of costs and benefits to consumers;
2. The transmission link provides a more favourable balance of costs and benefits to consumers than the distribution link, for contributions towards the transmission link lower than around £394m; and
3. The difference between transmission link and distribution link options is largely invariant to the modelled scenarios.

## 5.3 Identifying the avoided cost counterfactual (**h**)

5.3.1 Baringa's cost and benefit analysis is carried out over 20 years, from 2023 to 2042. This duration corresponds to the shortest of the economic lives of the different options (20 years for the on-island power station), i.e. the time horizon over which all of the options would be operational. Undertaking an assessment over a longer time period, such as the lifetime of the links (45 years), would require making an assumption on the cost of refurbishment or replacement of both the on-island power station and the standby generator. Given the high uncertainty associated with this assumption, Baringa consider that limiting the CBA assessment to 20 years is preferable.

5.3.2 To avoid penalising options with a longer economic life, Baringa treat CAPEX, connection and GSP costs as upfront payments. Baringa annuitize these values over the lifetime of the asset, using the WACC of the developer as the relevant rate feeding into the calculation of the CAPEX annuity. This means that, for the on-island plant, Baringa account for the totality of the CAPEX, while for the distribution link, Baringa only account for the first 20 years of CAPEX. This accounts for the longer economic life of the distribution link.

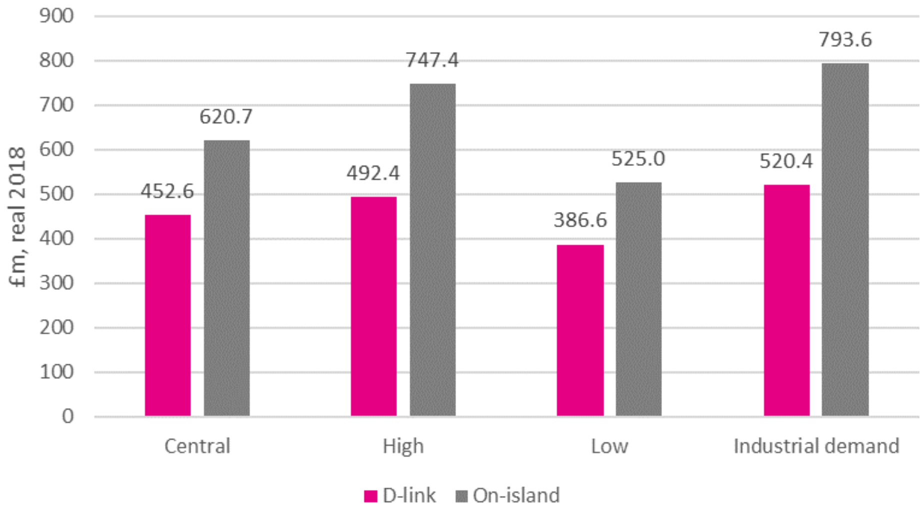
5.3.3 The output of the CBA is the net present value ('NPV') of the costs of each option: annual costs are discounted to their present value to ensure that differences between the dates at which they are incurred are taken into account.

5.3.4 SHEPD would note that this value does not include the costs of the mid-life refurbishment that the distribution link would have needed to complete at around year 25. Using the recommendations of

Mott MacDonald on timing and costs SHEPD have recalculated this value to extend over a 45 year period, and believe it should be c.£394m.

5.3.5 In all modelled scenarios, Baringa find that the on-island power station is significantly more expensive than the distribution link. For example, expected costs of meeting Shetland demand over 2023-42 are £452.6m in the case of the distribution link and £620.7m in the case of the on-island generator. The finding that the distribution link is significantly cheaper than the on-island plant matches the conclusions of the previous NES assessment carried out in 2016-17. The costs associated with the 2017 NES options are presented in Figure 5 below.

**Figure 5: Comparison of the distribution link and on-island plant options (NPV of total cost)**




5.3.6 The detailed cost breakdown of the 2017 NES options is presented in Figure 6 for the central modelling case (respectively £452.6m and £620.7m as highlighted in Figure 5). Although CAPEX associated with building a distribution link is higher than the CAPEX of a new diesel power plant, the cost advantage of the distribution link solution comes from the fact that it enables power imports from mainland GB. Such imports, even when accounting for the cost of substantial cable losses, are significantly cheaper than the cost of production of a similar amount of electricity by an on-island power plant which includes high fuel and carbon costs.

**Figure 6: Cost breakdown of the 2017 NES options – central scenario**

[redacted]

5.3.7 Figure 6 shows that the distribution link costs mainly correspond to CAPEX costs, to the cost of power imports and to the value of FOM. For the on-island plant, the largest cost item is utilisation costs (comprising VOM, fuel and carbon costs), followed by FOM and CAPEX.

5.3.8 Although CAPEX associated with building a distribution link is higher than the CAPEX of a new diesel power plant, Figure 6 shows that the cost advantage of the distribution link solution comes from the fact that it enables power imports from mainland GB. Such imports, even when accounting for the cost of substantial cable losses, are significantly cheaper than the cost of production of a similar amount of electricity by an on-island thermal power plant which includes high fuel and carbon costs.

5.3.9 The benefit of building the distribution link over the on-island plant is the difference between the costs of the on-island plant and the costs of the distribution link. In the central case, the benefit of the distribution link corresponds to the net avoided costs of the on-island plant, i.e. £620.7m - £452.6m = £168.1m.

*Conclusion*

5.3.10 Baringa conclude that the distribution link is the preferred NES option, in that it results in lower costs for consumers. The distribution link is therefore the benchmark against which the transmission link will be assessed.

## 5.4 Transmission solution assessment

5.4.1 The costs and benefits of the transmission link option are then assessed on the same basis as those of the NES options.

- Baringa models outcomes in the Shetland electricity market using its MDM model and reflecting this new system configuration;
- The costs and benefits of the transmission link option are compared to those of the best NES option. The value of the contribution identified at the stage of CfD modelling is the transmission link CAPEX component that Baringa has considered in the cost benefit analysis.

5.4.2 Baringa's MDM models the Shetland electricity system in the case where a transmission link is built and Shetland-based wind capacity is delivered in the upcoming CfD auction. Baringa determine outcomes under a range of scenarios, including Low/Central/High commodity prices, High additional industrial demand, and different combinations of wind farms being built on Shetland. For each modelled scenario, Baringa obtain the transmission link utilisation profile, losses and the generation profiles of all Shetland-based generators, and calculate the cost of meeting Shetland's electricity needs under the transmission link option.

5.4.3 Baringa then undertake a cost benefit analysis for the transmission link using the same methodology as for the NES options. The only notable difference between the approaches for NES options and the transmission link relates to the corresponding CAPEX values. In the case of the NES evaluation, Baringa has used CAPEX values submitted in the competitive tender, and updated to account for inflation.

5.4.4 The transmission link CAPEX treatment is different because the transmission link would be shared between Shetland wind and Shetland demand. More specifically, the cable would be used to export Shetland wind most of the time, but would also enable power imports into Shetland, when Shetland wind generation is too low to serve demand. Because the share of transmission link CAPEX covered by developers is borne by a private party, the DSO contribution is the only portion of the overall transmission link CAPEX which has a welfare impact on consumers. Baringa therefore consider that the element of transmission link CAPEX modelled in our CBA should be limited to the value of any DSO contribution to cable costs.

5.4.5 The other material difference with the NES options is the fact that large wind farms would be built together with the transmission link. Electricity produced by these wind farms, together with transmission link imports, would be the main sources of electricity for Shetland. Because large scale wind farms are able to export their electricity to the mainland through the transmission link and would earn GB power prices, Baringa assume that they also sell their production to Shetland consumers at GB power prices.

5.4.6 Finally, to account for differences in accrual of costs and benefits between the transmission link and the distribution link options, the final costs and benefits are calculated on an NPV basis. The preferred solution is the option with the highest net benefit for consumers.

5.4.7 Finally, Baringa compare the costs of the transmission link against the costs of the best NES option. Baringa find that the size of the DSO contribution is the key factor in determining whether the transmission link or the distribution link is the desirable solution for Shetland. Indeed, Figure 7 shows that the transmission link is significantly less expensive than the distribution link when there is no DSO contribution (though this scenario risks losing the solution, and all associated benefits). Figure 8 shows that the costs of meeting Shetland's demand with the transmission link are the same as under the distribution link for a contribution value of £376m.

5.4.8 This means that, for DSO contribution values up to £376m, the transmission link is cheaper than the distribution link and is the preferred option. As the DSO contribution increases, so does transmission link CAPEX. For a contribution of exactly £376m, the costs of meeting Shetland demand are equal for the distribution link and the transmission link options, and consumers are indifferent between them. Finally, for a contribution beyond £376m, the transmission link becomes more expensive than the distribution link and the distribution link is the preferred option.

**Figure 7: Costs breakdown of transmission link vs distribution link: central case and no DSO contribution**

[redacted]

**Figure 8: Costs breakdown of transmission link vs distribution link: central case and DSO contribution of £376m**

[redacted]

5.4.9 The costs of meeting Shetland's electricity needs under different scenarios are summarised in Figure 9 and Figure 10, for no DSO contribution and a contribution of £376m.

**Figure 9: Costs of transmission link vs distribution link: no DSO contribution**

[redacted]

**Figure 10: Costs of transmission link vs distribution link: DSO contribution of £376m**

[redacted]

5.4.10 When no contribution is needed, Baringa find that the transmission link is the cheapest option for meeting Shetland's electricity needs under all modelled scenarios. In this case, the benefits associated with the transmission link are the net avoided costs of building the distribution link. When a contribution of £376m is needed, there is no net benefit of building the transmission link in comparison of the distribution link. Finally, when the contribution is larger than £376m, the distribution link is the preferable option for meeting Shetland's electricity needs.

5.4.11 The largest benefit of the transmission link when compared to the distribution link (£244.7m in the central case with no contribution) differs from the maximum DSO contribution that makes consumers indifferent between the distribution link and the transmission link in our assessment (£376m). This is because the DSO contribution is calculated on the basis of the DSO acquiring 45 years of usage of the transmission asset, whereas the evaluation of the costs and benefits of the distribution link and the transmission link is done on the basis of a 20 year horizon. To incorporate the DSO contribution into the CBA analysis, the contribution value is annuitized and only the first 20 years of annuity payments are taken into account. This difference in time horizons explains why the largest benefit associated with the transmission link (estimated over 20 years) is smaller than the overall contribution value (estimated over 45 years).

5.4.12 To put this value into context, SHEPD have calculated the value to consumers on the same basis as above but using the Availability payments (and not the capital costs) which were scheduled to have been paid approved over the term of the Availability Agreement (net of Shetland GSP costs). This value is confidential but is higher than the value calculated using capex costs only. The range of possible "point of indifference" values associated with the 2017 NES is set out in Table 3 below.

**Table 3: Range of "point of indifference" values**

| Basis for value | Baringa valuation | Baringa valuation adjusted to include mid life refurbishment costs for 2017 NES costs |
| --- | --- | --- |
| Baringa Point of Indifference (Max Contribution Value) as an Upfront Payment, CBA Calculated Using Link and Standby Capex Costs | £376m | £394m |
| Baringa Point of Indifference (Max Contribution Value) as an Upfront Payment, CBA Calculated Using D Link Charge Rates | N/A | *Higher confidential value* |

# 6 Assessing the value of services from a transmission link

## 6.1 Assessing the distribution of costs between consumers and generators

6.1.1 Through engagement with Ofgem, SHEPD was asked to consider how it could identify the fair price or fair value that would be appropriate for distribution customers to pay to secure access to a transmission link solution. If that fair value is equal to, or less than, the benchmark alternative solution, the transmission option could be considered the recommended option.

6.1.2 Identifying the fair value of a contribution towards a transmission solution can be approached by either an analysis of how much of the cost savings should be shared with consumers, or what the value is to customers of the services provided by the asset.

6.1.3 On a cost savings basis, a simple economic evaluation would suggest that the fair value is the avoided costs minus £1 (£393.99m). This can be considered a logical outcome for a security of supply decision such as Shetland. SHEPD does not consider this to be the optimum outcome for consumers, as a value which does not reflect on the potential for further savings.

6.1.4 As described above, there is an imperative to secure demand supplies and this is bounded by a time-limited opportunity. Therefore, in order to maximise the potential successful transmission link, SHEPD could consider contributing a sum marginally lower than the benchmark.

6.1.5 SHEPD has investigated other cost saving based methodologies in order to determine a fair value contribution, including:

- the use of a typical distribution of benefit between a DNO and consumers, for example, the incentive applied to fast-tracked DNOs;
- estimating a hypothetical future discount a bidder might offer in a future competitive process;
- a contribution set as a proportion of the cost of the transmission link, where the proportion reflects the proportion of kWh flowing through the link or the proportion of time power is flowing from the mainland to the islands;
- a contribution set on the basis of a charging rate which reflects typical costs of a grid connection for a 50MVA demand development;
- a contribution set to reflect the costs of liquid fuel that would have been burnt in an island power station in the absence of a link;
- a contribution set to reflect the costs of liquid fuel that would have been burnt in an island power station in the absence of a link, plus the value of associated carbon dioxide emissions;
- a contribution set to the minimum amount needed for the transmission link to be built; and
- a contribution set such that the combined contribution from the DSO and through the TNUoS residual is the minimum needed for the transmission link to be built.

6.1.6 We set out our high level thinking on each of these methodologies below.

6.1.7 *Distribution of benefits*: It would be possible to use a benefit sharing mechanism based on precedent from utility regulators.

6.1.8 The benchmark NES 2017 value, £394m, can be considered equivalent to the outcome of a fast-track price control process. In this instance, the opportunity to reduce the ongoing network costs is recognised to be limited following submission of a well justified business plan. Similarly, the outcome of the NES tender process can be considered to be an efficient cost for the services provided.

6.1.9 Therefore, where the benchmark is considered efficient, customers consider retaining 30% of Totex reductions to be a fair outcome. This logic could also be applied in Shetland, where a reduction in the cost to customers of 30% could be considered a fair value. This equates to a fair contribution value of £276m (70% of £394m).

6.1.10 However, this approach does not assess the value of the services provided and, as such, SHEPD does not believe that this approach is optimal.

6.1.11 *Further tender rounds*: An alternative cost savings-based approach would be to evaluate the level of discount a bidder into a hypothetical future enduring solution competition could offer compared to the 2017 NES benchmark price published by Ofgem, with that discount being analogous to the value which should accrue to consumers.

6.1.12 Reflecting on feedback from its consultants, SHEPD does not believe that a reliable mechanism could be determined to produce a robust discount, although the range of 10% to 15% could be considered possible. Furthermore, it is possible that a future tender round would see increased costs to consumers.

6.1.13 *Proportion of kWh or time power is flowing to the islands:* Neither mechanism on its own would be expected to provide a sufficient contribution. However, the proportion of time mechanism forms part of the proposed stacked value of services fair contribution.

6.1.14 *Grid connection costs:* The benchmark for typical grid costs would be extremely subjective and subject to challenge.

6.1.15 *Combined DSO and TNUoS residual:* This would be complicated to implement and would require detailed data on the costs of generation projects and their investors' appetite, or establishment of a benefit sharing system ahead of the CfD auction.

6.1.16 *Avoided liquid fuel and carbon costs*: Unlikely to be fully representative of value of services if considered in isolation. The costs of fuel and of transporting it to the island might be confidential and difficult to forecast.

6.1.17 *Minimum contribution for the link to be built:* This would be complicated to implement and would require detailed data on the costs of generation projects and their investors' appetite, or establishment of a benefit sharing system ahead of the CfD auction.

6.1.18 All of these methods of allocating benefits to consumers appear arbitrary although they would still have utility as they deliver a benefit to consumers.

## 6.2 Recommended fair value test: stacked value of services

6.2.1 SHEPD has conducted additional analysis supported by CMS, Reckon and Baringa to investigate other mechanisms for establishing a fair value based on the support a transmission link provides to the distribution system. This analysis does not use avoided costs of alternative solutions but seeks to quantify the benefits a link would provide to the distribution system on Shetland. For the areas of support delivered there are no existing market valuation techniques for this support. SHEPD has therefore developed the following valuation mechanisms.

- *Control support:* offered via the highly effective control of the distribution system provided by an HVDC link converter station.
- *Capacity support:* as the link provides the instantaneous ability to satisfy any practical future Shetland demand at all times and at no notice.
- *Losses reduction*: the reduction in losses achieved because the proposed link operates at a higher voltage than the link proposed in the 2017 NES process.

*Value of control support*

6.2.2 The control arrangements on Shetland, such as system stability, are currently provided by conventional means of regulating a distribution system, e.g. LPS and SVT services. The HVDC converter station at Kergord, when connected to the distribution system, will provide an enhanced control service compared to conventional means. This allows significantly more intermittent generation, mixed with supplies of electricity from mainland GB. This service was also a benefit provided by the 2017 distribution link solution which SHEPD would have contracted for as part of the £40m per annum Shetland NES recommendation.

6.2.3 Without this support through a cable solution, the distribution system would require regulating by means of conventional generation, similar to the current arrangements. The system support service replaces thermal generation with local intermittent and GB mainland generated energy. Consistent with the 2017 Shetland NES, this service therefore has an inherent value which benefits SHEPD and GB customers.

6.2.4 The value of this service has been calculated based on the special carbon reductions that would be realised by reducing the current carbon intensity on Shetland to that of GB, based on BEIS forecasts of carbon intensity and price, and produces a present value of £115.6m (see Table 5).

6.2.5 It should be noted that the 75% renewables penetration scenario saving takes no account of the economics of such a level of renewables on Shetland where the technology required to achieve 75% penetration may not be economically viable. Therefore, this mechanism for calculating the contribution has been discarded and the value ascribed to the control functionality is that associated with achieving GB carbon intensity. This value is calculated using a similar mechanism to that used by Baringa to calculate the benchmark value i.e. the value is the capital sum which would produce a 45 year annuity where the first 20 years of the annuity would balance the 20 year CBA.

*Value of peak demand capacity support*

6.2.6 The link provides approximately twelve times the capacity required to satisfy Shetland demand. This capacity is immediately available at no notice (assuming the link is in service) which is an effective long term guarantee of the ability to satisfy Shetland peak power demand. Even though this supply would be provided at all times the link is energised there are particular times of support when the link provides power to distribution consumers because there is insufficient renewable energy being generated on Shetland. There are a number of ways of valuing such a supply. The following have been considered:

- Peak Shetland power demand as a percentage of the link rating.
- Shetland energy demand as a percentage of the expected maximum export via the link.

- Peak Shetland power demand as a percentage of the rating of the anchor project (the smallest proposed project necessary for the jink to be justified - currently the Viking Energy Project).

- Shetland energy demand as a percentage of the expected maximum export from the anchor project.

- Percentage of the year where the link exports to GB are less than Shetland peak power demand, i.e. the amount of the year when the link guarantees that Shetland peak power demand can be satisfied.

6.2.7 The analysis has been undertaken against expected data provided by the SHE Transmission Needs Case team or data which is publicly available.

6.2.8 It is noted that the distribution connection does not drive any change in specification pf the transmission link.

6.2.9 The options above which compare Shetland demand to the rating or export flows of the link do not take account of the ability of the link to instantaneously satisfy Shetland demand at any time and at no notice. The most appropriate mechanism is considered to be the percentage of the time that the link could be required to import energy to satisfy Shetland peak power demand, at 17.4%, and that the value the link provides to distribution consumers is 17.4% of the project capital cost.

6.2.10 It should be noted that the WSP demand forecast used for this analysis was agreed with Ofgem for the 2017 NES process and covers the period 2015 to 2040. It takes account of a low level of demand side management and energy efficiency measures. The values in the table above are the central case for the year 2025 and were the values tenderers to the 2017 NES process were told to assume.

6.2.11 The standby power station would be unable to provide automatic and immediate capacity support to distribution consumers in response to an unpredictable drop in wind generation unless it was operating at the time, burning significant quantities of fuel; this is unlikely, given it would be running only in link outage situations. It does not provide the same capacity service as the link and so has not been considered in the valuation.

6.2.12 The evergreen capacity support is being valued by the amount of time that the link would be needed to meet peak demand on Shetland. Data from SHE-Transmission shows that for 17.4% of the year, Shetland wind generation would be less than 50MW, which is a proxy for the amount of time in any one year that Shetland consumers would be dependent on the link to satisfy peak demand of 47.6MW.

6.2.13 This service was also a core provision of the 2017 Shetland NES Distribution recommended solution for which the tender process produced a total annual cost to distribution customers of £40m per annum over 20 years.

6.2.14 SHEPD values the capacity support service provided by the proposed transmission cable by assuming the service, when there is insufficient export, can be procured for discrete periods. Clearly a transmission link cannot be brought in and out of service during the year to satisfy peak demand. However, this is a rational economic approach to attributing the value the transmission link provides to one of the connected parties.

6.2.15 Furthermore, in the 17.4% of an average year when wind generation output is lower than 50MW generators connected to the cable are not utilising it and it has become an import facility. Therefore, attributing the proportionate share of transmission link costs on this basis is equitable.

6.2.16 This methodology attributes 17.4% of the value of the link cost of £709m[35] to distribution capacity support producing a fair value of £123m in present value terms.

*Value of reduced losses*

6.2.17 The proposed transmission link will deliver electricity to Shetland with lower losses per unit of energy transmitted than the 2017 NES link because it operates at a higher voltage of +/-320Kv compared to the proposed 2017 NES distribution link which was to have operated at +/-88kV.

6.2.18 In practical operation some of the energy generated by the transmission connected windfarms will be diverted to the distribution system and not exported to mainland GB. This netting off effect reduces the electrical losses on the HVDC link. However, this in effect increases the export capability of the link for the same level of electrical loss.

6.2.19 The alternative way to consider the losses is to consider the proposed transmission link as two different notional links, one solely for exporting wind generation to GB and rated at 600MW and a second link which is solely for supplying demand consumers on Shetland and rated at the Shetland demand. The losses from second "demand" link can be compared with the losses for the 2017 NES distribution link for the same Shetland demand scenarios. The value calculated is shown in Table 5.

*CBA approach*

6.2.20 SHEPD considered the fair value tests on both a 20 year and 45 year CBA basis, as set out in Table 4 below. We recommend the lower value on the basis of taking a more conservative approach.

**Table 4: Range of fair value test values**

| Fair Value Test Element | Reduced Losses and Control Element Calculated Through an Annuity from 20 Year CBA | CBA over 45 Years |
|---|---|---|
| Reduced losses and enhanced control elements only | £125.3m | £153.1m |
| Capacity element calculated as 17.4% of the Needs Case capital cost of £709m | £123.3m | £123.3m |
| **Total value** | **£248.6m** | **£276.4m** |

*Total estimated stacked value of services*

6.2.21 Each of these three services are complementary. The values have been added to calculate a stacked valuation, shown in Table 5 below:

[35] This is the current cost estimate which may change as the link project progresses, e.g. during the Project Assessment stage. If the link cost changes, it is expected that the contribution would also change.

**Table 5: Stacked fair value contribution**

| Service | Value of service |
|---|---|
| Year-round control services | £115.6m |
| Reduced losses | £9.7m |
| Peak demand support | £123m |
| **Total Stacked Value (2018 prices)** | **£248.6m** |

## 6.3 Recommended contribution value

6.3.1 SHEPD recommends that the total stacked value be used to set a level of contribution to the cost of the link of £249m which is a consumer saving of £145m against, or 37% lower than, the cost of undertaking the next best enduring solution.

## 6.4 Applicability to other islands (**c,e,l**)

6.4.1 This workstream concentrates on Shetland, further to SHEPD's licence obligations and the critical nature of the need for an enduring solution. However, SHEPD is mindful that other transmission links are proposed to the Western Isles and Orkney. These could also offer consumers savings from avoided future distribution costs and improved functionality. Analysis is underway to identify whether these savings exist. These are being confirmed by a detailed analysis, and SHEPD will provide Ofgem with its final view on these values shortly.

## 6.5 Assumptions

*Link cost* (**i**)

6.5.1 The value of the "peak demand support" element of the recommended fair value test is derived from the link costs. SHEPD would propose to revise and this element of the contribution further with any updated link costs ahead of the CfD auction. SHEPD would in turn expect Ofgem to communicate to stakeholders the effect of this revision on its decision consultation ahead of the CfD auction. Our understanding is that updated information will be available in Q1 2019.

6.5.2 To this end, we seek Ofgem's early assessment and support for the methodologies which use these assumptions in order that updates are timely and effective. This will provide for the revision of the contribution value at the relevant time.

6.5.3 We will work with Ofgem to determine the timing of these updates, in the context of associated regulatory processes.





Scottish & Southern Electricity Networks

# 7 Contribution implementation

## 7.1 Why is a contribution methodology required?

7.1.1 Where SHEPD has identified a recommended technical solution (connection to a transmission link), and a fair value for the service this asset provides (the fair value test), it is required to determine a means by which the contribution is put into effect. SHEPD has sought to approach this by using independent industry experts to explore the range of options and provide evidence of the pro and cons of each solution.

7.1.2 SHEPD has then referenced this supporting evidence in reaching its recommended contribution methodology proposal. Where SHEPD has concluded there is additional information to that provided by its consultants which justifies its solution, this will be highlighted.

## 7.2 Reckon report methodology

7.2.1 SHEPD engaged Reckon to review the range of potential contribution methodologies and assess the benefits and risks of the preferred shortlist of options.

7.2.2 The purpose of the contribution methodology is to provide a set of commercial and regulatory arrangements to govern cases where a DSO makes a financial contribution towards a new transmission link to an outlying distribution system (e.g. a Scottish island) in a situation where the needs case for the construction of the transmission link depends on it being used both for generation and demand: at times where there is a large amount of power generation on or near the island, the transmission link transports power to the main part of the transmission system; at times where there is a positive net demand on the outlying distribution system and no other local generation, the link meets that demand by transporting power to the island. The transmission link also provides frequency control for the island system.

7.2.3 Any contribution methodology will need to operate within the wider regulatory regime, including the regulatory duty to have regard to the need to secure that licence holders are able to finance their regulated activities.

7.2.4 The report identifies four principal dimensions, which each need to be considered in order to design a contribution methodology. The four dimensions are:

1. The nature of the contribution, including the identity of its recipient.
2. The timing of the contribution.
3. Whether beneficiaries of the link other than the DSO and transmission-connected generators should contribute.
4. How the amount of the contribution is optimised.

7.2.5 SHEPD has provided Reckon's Methodology Statement to Ofgem as part of its submission.

## 7.3 Conclusions of Reckon report

7.3.1 Reckon was engaged to investigate the ways that SHEPD might make a contribution. Through a number of workshops attended by SHEPD, Baringa, CMS and Reckon, an initial 19 different options were reduced to four conceptual options for further consideration by Reckon:

1. DSO payment under contract with NGESO
2. Special transmission charge calculated and levied by ESO on the DSO
3. DSO payment under contract with link owner
4. DSO payments under contracts with generators

7.3.2 In finalising their analysis, Reckon concluded that a contribution by the DSO towards the costs of a transmission link should be delivered by one of the two routes identified above (unless analysis of issues beyond their scope uncovered advantages to other options for the nature of the contribution): Option 1 - The contribution is paid to the ESO and offset against generation TNUoS charges through an annual payment that would require a simple modification to the transmission network use of system charging methodology; Option 4 - The contribution is paid under contracts directly to generators.

7.3.3 It should be noted that these conclusions were premised upon Reckon's understanding that options 2 and 3 presented more onerous implementation routes. SHEPD has provided Reckon's report to Ofgem with its submission.

## 7.4 Refinement of options

7.4.1 In moving towards a recommended contribution mechanism, SHEPD reached the following conclusions.

7.4.2 *Payment to generators*: SHEPD has ruled out making direct payments to generators due to the regulatory and legal complications. Furthermore, the total value of the contribution would be conditional on number / size of generation which was successful in the 2019 CfD round. In addition, this methodology would need to accommodate the impact of future generation connecting to the transmission network.

7.4.3 *Upfront payments*: Reckon does not recommend paying any contribution as an upfront capital sum. Much of this concern is based on the risk of the receiving party exiting the Shetland market.

7.4.4 SHEPD does not consider that material risks arise from upfront payment of a capital sum to another electricity licensee. Further, scenario modelling suggests that an upfront payment does produce a consumer benefit relative to annual payments through simplicity, certainty, and a smaller contribution to achieve the same TNUoS reduction.

7.4.5 SHEPD is of the opinion that all modifications to the transmission network use of system charging methodology introduce risks. First, the risk associated with the introduction of complexity and second, the potential for delays in approval which risk the loss of the opportunity for consumer savings. Options which minimise the impact on wider industry codes without a loss in other benefits, are therefore preferred.

7.4.6 Accordingly, SHEPD has identified and developed a further option. The DNO-DSO makes an upfront capital contribution to the cost of the link through a payment to the TO. The TO reduces the "Base Circuit Capital Cost" which it notifies to the ESO as the base cost for the calculation of the TNUoS charges for the HVDC link. Any totex payment by the DSO would increase the Regulated Asset Value (RAV) of the DSO. Any offsetting contributions received by the TO reduces its RAV additions. SHEPD is of the opinion that a limited licence modification at the discretion of Ofgem would allow this mechanism to occur.

## 7.5 Recommended contribution mechanism

7.5.1 Due to the simplicity of the process and the slightly higher effectiveness of doing so, SHEPD recommends that any contribution be paid via a capital contribution and consequent reduction in the actual “Base Circuit Capital Cost” used by the ESO to calculate the TNUoS charges for the Shetland link.

7.5.2 Such a capital contribution would be made when the link enters service and would be funded through an increase in the RAV of the DSO and consequent reduction in the RAV of the TO.

7.5.3 If confirmed, there would be no need to amend the CUSC and the licence changes could be limited to the networks involved in the transaction. Small changes would be expected in the Regulatory Instructions and Guidance (RIGs) which can be accommodated through the annual revision process.

7.5.4 CMS have conducted a high level review of the regulatory aspects of the considered and recommended contribution mechanisms. These are not intended to provide a comprehensive and exhaustive review of all legal and regulatory obligations, rather they seek to identify some of the key items that Ofgem may consider in respect of the recommended contribution mechanism. CMS are carrying out a review of the requirement for any further material implementation activities.

# 8 Ofgem role and regulatory process (d)

8.1.1 SHEPD has had initial engagement with Ofgem during October 2018 to discuss the regulatory process to review, consult and decide on the recommendation in order to reach a position of clarity and certainty ahead of the 2019 CfD auction. The following table sets out SHEPD's concept of the regulatory process.

**Table 6: Outline regulatory process**

| Activity | Date |
|---|---|
| SHEPD submission of recommendation to Ofgem | Nov 2018 |
| Ofgem review of recommendation (incl any SQ process)** | Nov 2018 |
| SHEPD potential refinement of recommendation and associated analysis further to Ofgem review | Nov 2018 |
| SHEPD recommendation workshop with Ofgem and consultants | Mid-Nov 2018 |
| SHEPD further BEIS (/Ofgem) engagement on recommendation | Mid-Nov 2018 |
| Ofgem November GEMA board | 15/11/2018 |
| Ofgem minded-to decision on costs / methodology of recommendation for consultation** | 03/12/2018 |
| Ofgem December GEMA board | 13/12/2018 |
| Ofgem minded-to consultation on costs / methodology of recommendation** | Dec 2018 – Jan 2019 |
| Ofgem review of consultation responses** | Jan 2019 |
| SHEPD potential refinement of recommendation and associated analysis further to Ofgem review of consultation responses | Jan 2019 |
| Ofgem decision on costs / methodology of recommendation** | 04/02/2019 |
| Implementation of contribution methodology - as far as required pre-auction (subject to contribution mechanism); potential refinement of certain assumptions | Feb – Apr 2019 |
| Final execution of DSO contribution arrangements* | Late 2019 onwards |

* Dates tbc

** Dates tbc by Ofgem

Ofgem activities

SHEPD DSO workstream

8.1.2 The process includes the following key stages:

1. Submission by SHEPD
2. Review by Ofgem, and associated refinement by SHEPD
3. Consultation
4. Review of responses by Ofgem, and potential further refinement by SHEPD
5. Ofgem decision

8.1.3 A decision on a contribution needs to be published in adequate time ahead of the CfD auction, with adequate clarity and certainty on implementation, to allow relevant stakeholders (TO, NG and generators) to take account of its effect.

8.1.4 We consider that a minded-to decision in December 2018, and a final decision in February 2019 would be preferable; we would welcome discussion with Ofgem on both of these points.

8.1.5 We consider that the key elements of implementation of the contribution mechanism can be addressed by Ofgem with relevant parties following the CfD auction, allowing this process to be initiated later in 2019.

8.1.6 SHEPD notes Ofgem's feedback that its ability to meet the timescales set out is directly affected by the complexity of the recommendation. In reaching our conclusion, we have focused on proposing a recommendation that avoids unnecessary complexity both in identifying a contribution value, and in its implementation.

8.1.7 We consider that this process should not lead to any change in Ofgem's consideration of the Shetland Needs Case, given that it is premised on generator connections, associated commitments, and CfD success.

# 9 Cost recovery (j)

9.1.1 In its July 2016 decision on its review of the Common Tariff Obligation and Hydro Benefit Replacement Scheme, BEIS noted its intent to move Shetland subsidy recovery from North of Scotland distribution consumers to GB-wide recovery, using the existing HBRS mechanism: "The Government…remains committed to the introduction of GB-wide funding for a Shetland cross-subsidy at the same time that Shetland's new energy solution is implemented. This will be delivered through the Hydro Benefit Replacement Scheme, and we would expect to be able to confirm full details for this by the time of the next review."[36]

9.1.2 This intent was confirmed again to SHEPD during preparation to implement recovery of the subsidy amount associated with the 2017 NES. However, the full implementation details were not developed, further to Ofgem's decision to reject the proposals in November 2017.

9.1.3 This year SHEPD and Ofgem (RIIO 1 Costs and Outputs team) have had further engagement with BEIS, during which BEIS has reaffirmed its intention to move to HBRS recovery potentially as early as 2020.

9.1.4 To this end, BEIS has asked Ofgem and SHEPD to map out relevant cost recovery arrangements for drafting into the HBRS Statutory Instrument.[37] SHEPD and Ofgem expect to confirm drafts to BEIS before Christmas 2018, for the purpose of review by Ministers in the new year.

9.1.5 We would be happy to provide any further information on this, including the integration of these arrangements with the proposed contribution mechanism, as required.

[36] Hydro Benefit Replacement Scheme and Common Tariff Obligation - Three-year review of statutory schemes: Government Response, July 2016, p.4

[37] The Energy Act 2004 (Assistance for Areas with High Distribution Costs) Order 2005

# 10 Next steps (d,k)

## 10.1 Regulatory process

10.1.1 Subject to further feedback from Ofgem, SHEPD would expect the regulatory process to progress as set out in section 8, noting Ofgem's caveats on timing, and is preparing to ensure the Supplementary Questions (SQ) phase is effective and efficient. Building on its successful experience during the Shetland NES process SHEPD proposes to complement the SQ phase through use of a workshop with Ofgem and key consultants on 20 November. This will aid the communication and dissemination of the key themes of the recommendation in detail and will allow us to answer initial queries.

## 10.2 Stakeholder engagement (c,e,l)

10.2.1 Over the SQ period, SHEPD will be carrying out engagement with SHE-T and NGESO in order to gain feedback on the contribution mechanism and implementation programme. It will also continue its engagement with BEIS and the Scottish Government to ensure they are comfortable with our approach.





**Amended for publication**

Scottish & Southern Electricity Networks