Consultancy Support for Ofgem's Cost Assessment of the proposed NSL Interconnector

Ofgem

24 June 2016

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List of Acronyms

AC	Alternating current
CDM	Construction design management
CIGRE	International Council on large electrical systems
EIA	Environmental impact assessment
EUR	Euros
EPC	Engineering, Procurement and Construction
FAT	Factory Acceptance Test
FIDIC	Fédération Internationale des Ingénieurs
FPA	Final Project Assessment
FTE	Full time employee
GBP	£
HSE	Health, Safety, Environment
HVDC	High voltage direct current
IET	Institution of Engineering and Technology
IGBT	Insulated Gate to Bi-polar Transistor
IPA	Initial Project Assessment
ITT	Invitation to Tender
MI	Mass Impregnated
MIND	Mass Impregnated Non-Draining
NETSO	National Electricity Transmission System Operator
NG	National Grid
NGET	National Grid Electricity Transmission Limited
NGIH	National Grid Interconnector Holdings
NGNSL	National Grid North Sea Link Limited
NOK	Norwegian Krone
NSC	Norwegian subsea contract
NSL	North Sea Link
OFTO	Offshore Transmission Owners

O&M	Operational and Maintenance
OPEX	Operational Expenditure
PMO	Project Management Office
PQA	Pre-qualification Assessment
PQQ	Pre-Qualification Questionnaire
REPEX	Replacement expenditure
SEK	Swedish Krona
SHEQ	Safety, Health, Environment, Quality
SHESQ	Safety, health, environment, security and quality
SO	System Operator
TAT	Type approval test
TO	Transmission Owner
TSO	Transmission System Operator
VSC	Voltage Source Converter
WECC	Western Electricity Coordinating Council
XLPE	Cross-linked polyethylene

Executive summary

The NSL (North Sea Link) Interconnector will connect the electricity transmission networks of England and Norway. It will have a capacity of 1400 MW and utilise VSC-HVDC converter technology at ±525 kV. The project will connect from Blyth in Northumberland to Kvilldal in Suldal County with 720km of Mass Impregnated subsea cable.

EPC contracts have been agreed with ABB for the delivery of the VSC converter stations and with Nexans and Prysmian for the cable installation, with lot 1 (Fjord section) awarded to Nexans and lots 2 and 3 (Mid-section and UK sections) awarded to Prysmian.

Atkins, CEPA, HVDC Tech and Powersure have, on behalf of Ofgem, reviewed the procurement strategy, the project management plan, the interconnector costs, the risk exposure and the hedging strategy employed by the project developers to ensure that they represent value for money for the consumer in the context of the Cap and Floor Regime.

Overall we have found that the procurement process and project plan has broadly followed best practice. Some areas of concern remain.O&M was tendered for as an option and we have not seen evidence of the weighting placed on O&M for selection of the preferred bid as part of a complete package. The developer's decision to agree significant changes to the FIDIC standard conditions of contract for the EPC contract of the converters, the PQA process and whether the developers have included programme contingency in the project plan to take into account specific risks.

The report also highlights concerns with respect to project management resourcing. In particular we are of the opinion that the project management resource numbers and costs have been underestimated. This is a particular concern taking into account the complexity of the project and novel technologies proposed.

A high level benchmarking exercise for the cable and VSC converter stations' EPC contract costs with respect to publicly available benchmarks and the EPC contract costs of comparable projects has been carried out on a £k/km and £k/MW basis. Based on this high level assessment we have found that the project developers have negotiated favourable EPC contract costs, and in particular with regards to the cable EPC contracts have shown the ability to drive down costs of the EPC contracts significantly. However we are concerned that these favourable contract costs have been achieved at the expense of increased risks to the developer in the case of both the cable and converter contracts. The risk contingency contribution of converters and cables stands at over [redacted] each of the individual element EPC contract costs. The overall risk contingency calculated stands at over [redacted]. We therefore recommend that further in-depth analysis is carried out in this area. In the case of the cable contracts we have identified substantial re-measurable items giving rise to a provisional component of the contract worth [redacted] of the overall contract value. Again we recommend further in-depth analysis and bottom up benchmarking of the costs and requirements of these provisional sums, and advise Ofgem to be clear and set up robust processes to manage and protect consumers from excessive CAPEX increase over the delivery period.

This report contains an independent assessment of the risks associated with the contract and project plans. As part of this assessment specific technical, legislative and installation related risks have been identified which have either not been highlighted by NSL or have insufficient mitigation in place. These risks either impact the programme schedule or the cost of the project. While many of these risks are intended to be managed by liquidated damages, specifically where there are delays by contractors, once these are settled there are few incentives for the contractors to keep to timetable. This would ultimately lead to increased CAPEX with the developer spending extra time carrying the Project Team. Throughout the report, on each individual item of assessment we have highlighted significant risks. We have recommended that Ofgem discusses the risks we have identified with the project developers to understand the steps taken to mitigate their impacts. We also recommend that the cost assumptions underpinning the P70 risk contingency assessment are scrutinised in greater detail given our concerns of the value of the risk contingency as a proportion of the EPC contract values.

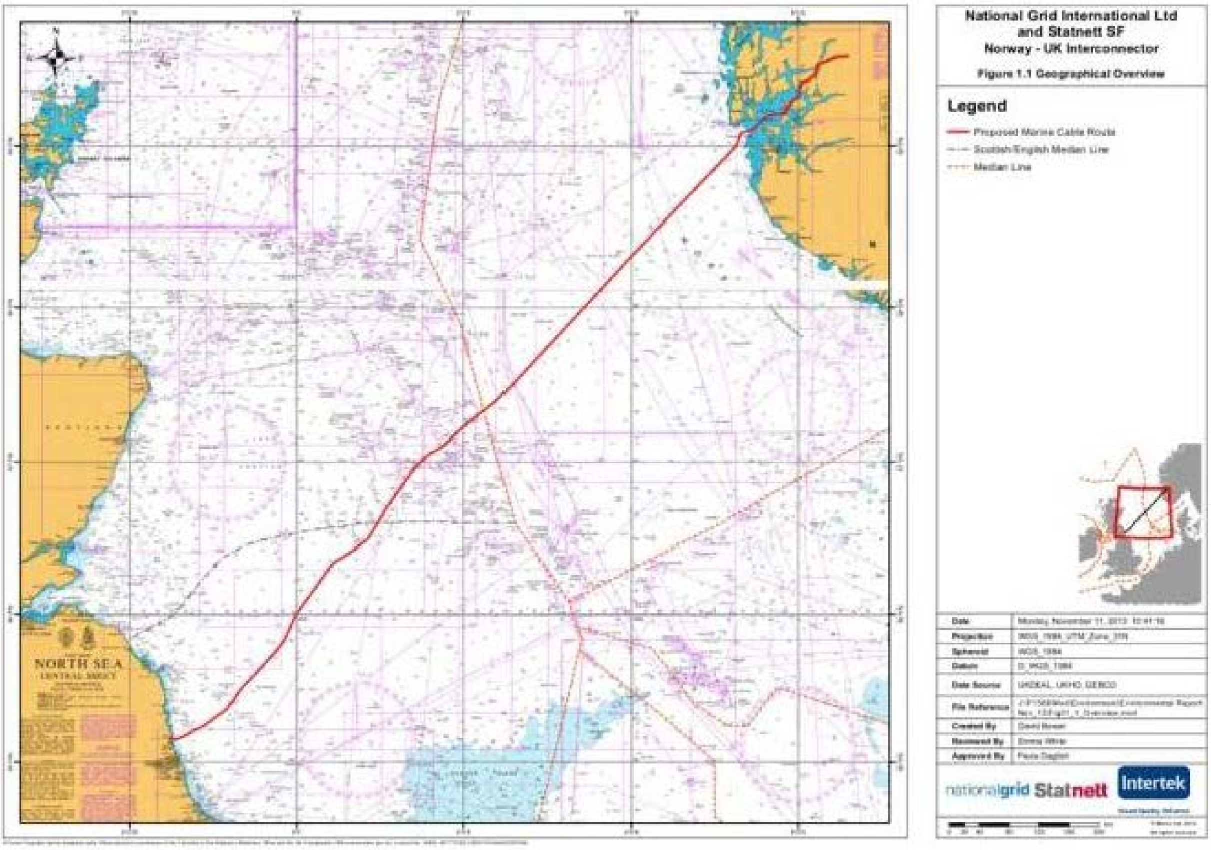
Finally the report highlights that the information provided to us around the hedging strategy employed by project developers has not taken into account alternative positions which could have further reduced the capital cost of the project..

1. Introduction

1.1. Introduction to the NSL Project

The NSL (North Sea Link) Interconnector will connect the electricity transmission networks of England and Norway. It will have a capacity of 1400 MW and utilise VSC-HVDC converter technology at ±525 kV. The project will connect from Blyth in Northumberland to Kvilldal in Suldal County. The offshore cable route is given in Figure 1-1 below.

Figure 1-1 NSL Offshore Cable Route



National Grid North Sea Link limited (NGNSL), a subsidiary arm of National Grid Plc, and Statnett, the Transmission System Owner (TSO) for Norway, will own and operate the project on a near 50:50 basis with Statnett owning the eastern part of the physical assets and NGNSL the western part of the assets.

The selected technology for the project is a bipole VSC-HVDC system operating at ±525kV to achieve the expected power transfer capability of 1400 MW. This will be the one of highest installed voltages for a VSC-HVDC converter project to date with only one other project around this voltage (Skagerrak 4) commissioned so far. The bipole system requires two HVDC cables to be installed. The selected technology for the cables is Mass Impregnated (MI) rather than Cross-Linked Polyethylene (XLPE) due to the high voltage of the project. XLPE cables in mass production are currently limited to around 320 kV. We note that the NEMO interconnector between GB and Belgium is the first project to use XLPE cable ratings at 400 kV. The technology limitations are expected to improve with increasing development in the market although at this point in time the choice of MI cable is deemed appropriate based on the capability of cable technology.

EPC contracts have been agreed with ABB for the delivery of the VSC converter stations and with Nexans and Prysmian for the cable installation with lot 1 (Fjord section) awarded to Nexans and lots 2 and 3 (Mid-section and UK sections) awarded to Prysmian. These contracts are analysed in more detail in section 2 of the report.

1.2. Report Requirements

This report summarises our analysis of the following areas:

- Review of the procurement strategy of the developer;
- Ensure that the project management strategies are appropriate;
- Review of the interconnector costs to ensure that they are reasonable and represent value for money for the consumer;
- Confirm whether the risk exposure and allocation is appropriate;
- Assess the hedging strategy.

The assessment has been split by asset type as follows:

- Subsea cable and underground cable;
- Converter stations and associated Civils work;
- Developer costs, including project management, land purchase/ lease costs, resourcing and other minor contractual costs.

This report is therefore structured as follows:

- Section 2 reviews the procurement processes, project plans and tender processes;
- Section 3 provides an assessment of the project management resources, costs and organisation;
- Section 4 assesses the capital and installation costs of the project split between the HVDC converter station and the cable costs;
- Section 5 assesses the main project risks and contract risks, aims to quantify the level of these risks and outline any residual risks to the consumer;
- Section 6 contains a discussion on the Hedging strategy employed by the project developers;
- Section 7 presents our Conclusions.

2. Procurement, project plan and tender process

In this section we will analyse the procurement process, project plan and the tender evaluation criteria employed by National Grid NSL and Statnett.

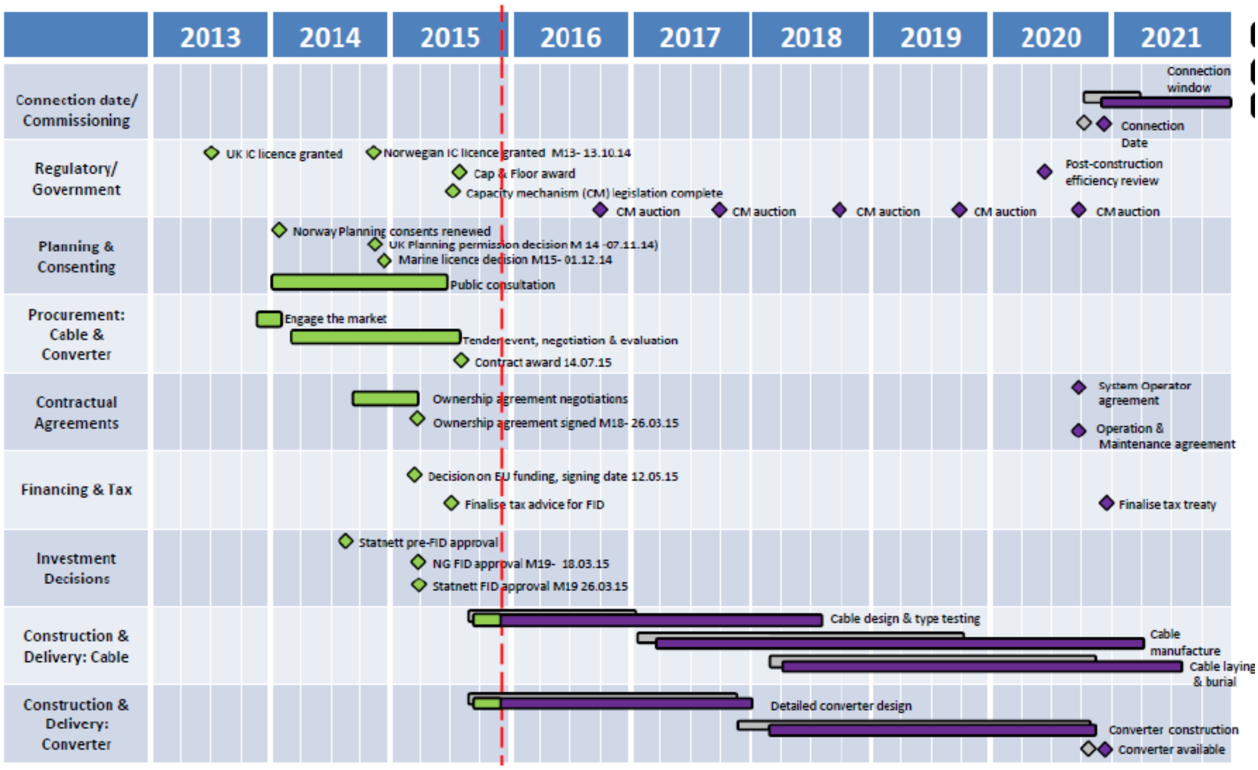
National Grid NSL and Statnett adopted an EPC procurement approach. The procurement process was divided into two main activities: Supply and installation of a 525 kV HVDC cable for a route of over 700 km across the North Sea between Kvilldal, Norway and Blyth, United Kingdom and the supply of installation of a 525 kV bipole voltage source convertor (VSC) stations at each of Kvilldal and Blyth converter stations.

We note that the process only covered capital cost of the equipment. For the converter stations for example,Operation and Maintenance Agreements were considered as options during the ITT and the option provided within the contract but we have not been able to verify the weighting attached to O&M as part of the selection process and note that these have not been included in the contract price (exhibit B of ABB contract). We are therefore unsure whether these will be triggered,s part of this framework with the contractors or through competitive tendering. Our experience suggest that this is inconsistent with best practice in terms of whole life asset management. It is our understanding that the Ofgem FPA assessment also aims to consider capital costs only excluding Opex and Repex. It is worth noting that particular synergies can be developed by considering these areas as part of the overall procurement process leading to better value for money. NSL do not seem to have considered the possibility of tendering for these aspects even if optional. Having these costs up front would give a better view of whole life costs, and create incentives for companies to build assets that need limited maintenance or which can be easily maintained.

Figure 2-1 below shows the procurement process followed by NSL. The soft market testing (Strategy) part of the process was completed in July 2013, and contract award was finally completed in July 2015. The time period for completion of the two tenders was therefore significant. It allowed 5 months for the tender event which included launch events to pre-qualified bidders specific to the project. The tender process appears to be very thorough and follows best practice. The same process was followed for the non-EPC contracts (although with different timings). Figure 2-2 describes the NSL project plan to connection. We have commented on the appropriateness of the timescales for delivery in our discussion on the specific contract sections below.

Figure 2-1 Milestones in procurement plan

Figure 2-2 NSL Project Plan to Connection



2.1. Procurement of EPC

Both multi-contract and EPC approaches to the design, manufacture and installation of the cables and converter stations were considered. Although the two elements were tendered separately and the cable procurement was run as three separate lots, each individual contract follows the EPC approach. Whilst it is good practice to consider both EPC and multi-contract strategies, Atkins agrees that the selection of an EPC approach for each main element of the project is optimal for construction of a project of this type and scale. There is very limited global experience in procuring HVDC projects via a multi-contract approach and therefore this approach would have led to significant increased risk.

Use of FIDIC contracts was agreed for the converters but the FIDIC terms were amended to reflect the variations procedure in the NSC 05 terms. It is not clear why NSL have agreed these deviations from the standard FIDIC contract structure and how NSL have assured themselves that the implications of these changes is fully understood. This is an area where further clarification is required from NSL.

One of the amendments to the FIDIC standard schedule has been to remove the Dispute Adjudication Board (DAB) and therefore unresolved disputes are referred directly to the Norwegian Arbitration Act of 14 May 2004 (page 76 clause 20.2 – 20.6). The process of Arbitration under Norwegian Law requires one arbiter to be appointed by each party, with the two arbiters appointing a lead or chair arbiter. It is our understanding that these appointments and the arbitration process do not start until a request for arbitration is sent by one of the parties. The DAB on the other hand is usually appointed before construction begins and members of the DAB have periodic access to site, are provided with contract documents and hence gain considerable knowledge of the project prior to a dispute resolution process. Either party not abiding by the DAB's decision would be liable to prosecution under breach of contract terms. The removal of the DAB could therefore lead to delays and escalation of costs. We would advise Ofgem to discuss the risks to, and liabilities for the developer in detail, and consider how to treat variations arising from these in terms of their impact on UK consumers.

In terms of the form of the EPC contract for the cables, Statnett had a preference to use a standard Norwegian Subsea Contract (NSC 05) which has been developed with the offshore industry for use on subsea and marine operations on the Norwegian continental shelf. This had previously been used on the NorNed and Skagerrak 4 projects.

Within the NSC 05, if the contractor raises a variation order request (claim) and the company agrees with the requirement for variation of the works but disagrees with the amount of compensation, the company pays the full provisional compensation and is then required to start arbitration proceedings under the Norwegian arbitration act of 14th May 2004 within 6 months. If the company disagrees with the requirement for the variation, the company is required to issue a disputed variation order (this is done by default if the company does not agree with the requirement and fails to issue a variation order within a set deadline). Both parties are then required to appoint an expert who will decide on a provisional determination. Once again if the parties disagree with this verdict, arbitration proceedings are required under Norwegian law. However in the case of the NSC 05 contract any works under a disputed variation order has to be carried out without undue delay by the contractor hence limiting any delays.

2.1.1. Cables

Generally for these types of projects, two main EPC contracts are procured: one for the converter stations and one for the cables. In this case, the cable has been split into three lots due to the considerable length of the route (the longest route yet to be built and 144km longer than NorNed). The three lots were identified as follows:

- Lot 1: Fjord section (including tunnel and Suldal Lake) route length: 255km
- Lot 2: Mid-section route length: 260km
- Lot 3: UK section route length: 210km

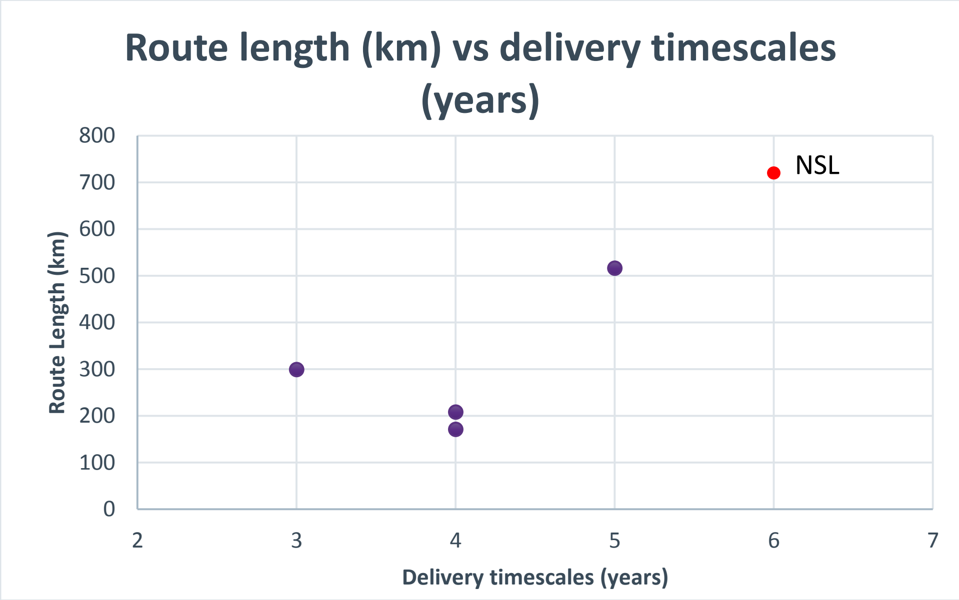
The actual cable supply length is twice the route lengths shown above. The contracts clearly define liability for payment of contractors. The costs are split equally between Statnett and National Grid NSL.

Cable supply and installation is affected by availability of a limited number of manufacturers and cable laying vessels. We believe that splitting the cable supply into lots is a sensible approach as it enables the cables to be supplied by different manufacturers to alleviate supply chain constraints and mitigate the risk of delay – the project is not entirely dependent upon a single supplier. This approach does however introduce other risks such as additional interface risks. It is difficult to evaluate whether supply chain risks have a greater impact than interface risks. However significant supply chain constraints are expected in the years around 2021 given the number of European interconnectors using MI cables expected to commission around 2020/2021 (example Nordlink, COBRA, etc.…). It is appropriate to mitigate against those risks.

Interface risks could be appropriately managed through effective project management. NSL have recognised these risks within their risk register and provided information on insurance cover for interface issues as well as risk mitigation proposals including contractual obligations to cooperate and develop a system for interface coordination, provision of information and establishment of an interface register.

The cable contracts were awarded in Q3 2015 and delivery and installation is scheduled for Q3 2021, i.e. a lead time of 6 years. Figure 2-3 below shows how the delivery timescales of some of the most recent MI cable contracts signed between 2015 and 2016 varies with route length. It can be seen that the increased length of the cable required for NSL, in our opinion, justifies the increased timescales. The outliers in this graph are two contracts signed for approximately 200 km route lengths. However, these were allocated to the same supplier and can be considered as a single 400 km production run.

Figure 2-3 Route length of cable contracts signed between 2015 and 2016 against delivery timescales



Due to the limited number of cable manufacturers and factories, the timeframe for the supply of cable is dictated by global orders and projects. In this case, NSL's cable delivery timeframe has already been revised from 2019 to 2021, prior to contract agreement, after NordLink revised its delivery date due to market constraints. Cable manufacture and delivery is particularly sensitive to the risk of delays during type test and manufacturing cycles. There must be a time cushion between the Type Approval Testing (TAT) and manufacturing in case problems develop during the Type Testing that may impact the cable or the system design. Certain parts of the TAT sometimes have to be repeated and this inevitably leads to delays. In some cases, repetition of type tests has led to a delay of 2 years. However, in this case the MI cable technology is well established and the cable voltage, as well as the conductor size, are within the manufacturing window of the suppliers.

Other than these risks, the consenting timeframe is always challenging, but the times are reasonable and there are no significant issues in the environmental impact assessment (EIA) that could lead to major issues. All of the contractors, equipment and processes have been carried out before and the cable technology itself has been proven to be robust and mainstream. Our view is therefore that the delivery timescales for NSL cables are in line with expectations.

The availability of installation vessels is also an issue and NSL's submission states that a two month delay caused by vessel unavailability could lead to a 6-9 month delay overall if activities have to be shifted into the following year. The risk register provided by NSL contains an entry with regards to this risk but it is not clear whether this delay has been taken into account in the overall programme. In terms of costs, NSL have in place liquidated damages within the contracts covering for the event where contractors fail to meet required milestones. [redacted] This would ultimately lead to increased CAPEX with the developer spending extra time carrying the Project Team.

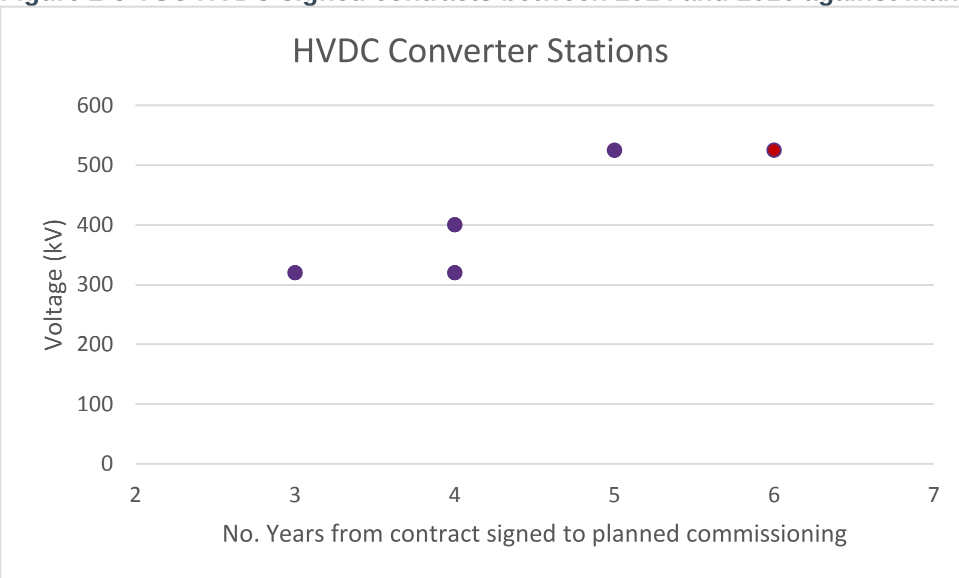
2.1.2. Converter Stations

The converter stations will utilise 525 kV VSC HVDC technology. The costs are split equally between National Grid NSL and Statnett. The proposed voltage will be the highest voltage to date installed for a VSC HVDC system. Figure 2-4 below shows how step changes in voltage levels for VSC-HVDC converters have progressed over time.

Figure 2-4 HVDC Light Development

Delivery date for the converter stations is due to be Q4 2020. This allows just over 5 years for development of the converter stations. In our opinion this is comparable to the typical delivery time for HVDC converter stations. Figure 2-5 shows the delivery timescales of VSC HVDC converter station contracts signed between 2014 and 2016 in Europe and their manufacturing voltages. At proven manufacturing voltages between 300 and 400 kV the estimated delivery timescales is between 3 and 4 years. The two recent 500 kV VSC HVDC signed contracts have a delivery timescale of 5 to 6 years allowing for the additional testing and design requirements of stepping to a higher voltage rating and MW capacity. It should be noted that the delivery timescales of HVDC converter stations are not directly scalable with voltage levels (as opposed to delivery timescales of cables which are proportional to the length). However in this case, the difference in delivery timescales represents the added complexity and testing requirements associated with a new technology. It is expected that as the technology matures, delivery timescales will approach 3-4 years as is currently the case for standard VSC voltages.

Figure 2-5 VSC HVDC signed contracts between 2014 and 2016 against manufacturing voltages



2.2. Procurement of non-EPC

NSL have provided information regarding procurement for the Kvilldal civils work and insurance cover as these works were procured prior to submission of the FPA. The costs of these works (termed site preparation costs) are picked up equally by the partners. Other non-EPC areas include some additional works at Blyth converter station. However these were procured post FPA submission and are not described in this document.

The non-EPC activities at Kvilldal include construction of a tunnel between Hylsfjordena and the Suldalsvatnet Lake, a micro tunnel between the fjord and the tunnel, a cable trench, ground work at the converter site, land fill sites and rock fall protection. This is the scope of the larger contract. Some smaller contracts were in the process of being awarded at FPA submission, e.g. relocation of Rjukan overhead lines, HVAC switchgear extension and strengthening of the Helganes bridge.

Five work packages were identified for these works, i.e. converter site preparation, tunnel, rock fall protection, micro tunnel and cable trench. Options to split the work packages between two contracts or contain within a separate contract were considered. After consideration, the option to combine all work packages into one contract was selected, although an explicit reason for this decision is not provided in the document. Atkins supports this approach as leading to fewer interfaces, enabling a greater focus to be maintained on the interface between this contract and the converter contract.

2.3. Tender Evaluation process

2.3.1. EPC Contracts

2.3.1.1. Cables

[redacted]

It is our understanding that 4 out of the 11 companies responded to the NSL PQQ with 3 suppliers taken to ITT stage. The PQQ scoring criteria is shown below.

Figure 2-6 Cable PQQ Scoring

PQQ SECTION	APPLICANTS			
	[redacted]	[redacted]	NEXANS SECTION PASS/FAIL	PRYSMIAN SECTION PASS/FAIL
4.0 Mandatory Questions (YES to all)	[redacted]	[redacted]	PASS	PASS
5.0 Finance Details	[redacted]	[redacted]	PASS	PASS
6.1 Technical Responses - Project Experience - Overall (See below for each Lot)	[redacted]	[redacted]	PASS	PASS
7.0 SHEQ (Mandatory - YES to all Questions)	[redacted]	[redacted]	PASS	PASS
8.0 Lot Application: (Lots Applicants applied for highlighted in yellow)	[redacted]	[redacted]		
Lot 1	[redacted]	[redacted]	PASS	PASS
Lot 2	[redacted]	[redacted]	PASS	PASS
Lot 2	[redacted]	[redacted]	PASS	PASS
OVERALL PASS/FAIL	[redacted]	[redacted]	PASS	PASS

The ITT scoring had the following weights:

1. Commercial – 55%
2. Technical – 16%
3. Execution and Performance – 29%

In this case the technical scoring had a reduced weight compared with the converters, reflecting the fact that cables are technically less complicated than converters. The technical questions reflected experience with Mass Impregnated (MI) cables of this voltage level. As discussed earlier the choice of MI over XLPE is a result of the technological readiness of MI compared to XLPE given the voltage rating required. This choice of technology could however precluded the smaller (and potentially more cost effective) players from entering the market. [redacted]

2.3.1.2. Converters

The PQQ process for the converters included a number of pass/ fail criteria designed to ensure that only companies with sufficient financial standing and technical competence were assessed in the ITT. It can be seen that only the well-known companies (i.e. [redacted]) passed the technical responses. [redacted]

Whilst it is essential that the converter manufacturers have the ability to deliver a competent technical solution, other smaller companies are now building up global track record and can generally offer lower costs. Therefore, there may be future benefit for developers to consider revising their ITT technical and financial requirements as well as their scoring to allow participation of such companies in future tenders.

[redacted]

PQQ SECTION	APPLICANTS
	[redacted]
[redacted]	

The ITT scoring had the following weights:

1. Commercial – 50%
2. Technical – 30%
3. Execution and Performance (including SHEQ) – 20%

The weightings were slightly different compared with the non-EPC contracts. The weightings reflect a slightly lower emphasis on cost and higher emphasis on technical and delivery. This is appropriate due to the level of technical complexity of the projects, whilst still giving a sufficient emphasis on cost.

2.3.2. Non-EPC Contracts (Kvilldal tunnel and site preparation)

Pre-qualification ensured that only companies that had a turnover above a defined threshold, had completed referenced work with contract value above a defined threshold and where a partnership between the two companies was accepted via a letter of intent were selected. This ensured that only the bids of competent companies were evaluated.

For the main non-EPC contract the evaluation criteria used were as follows:

1. Price and commercial terms – 60%
2. Quality and implementation ability – 30%
3. Health, Safety and Environment (HSE) – 10%

An evaluation matrix was used to document the scoring. Sub-parameters under the three main criteria were scored on a scale of 1-10 and the contract was awarded to the supplier with the highest overall score.

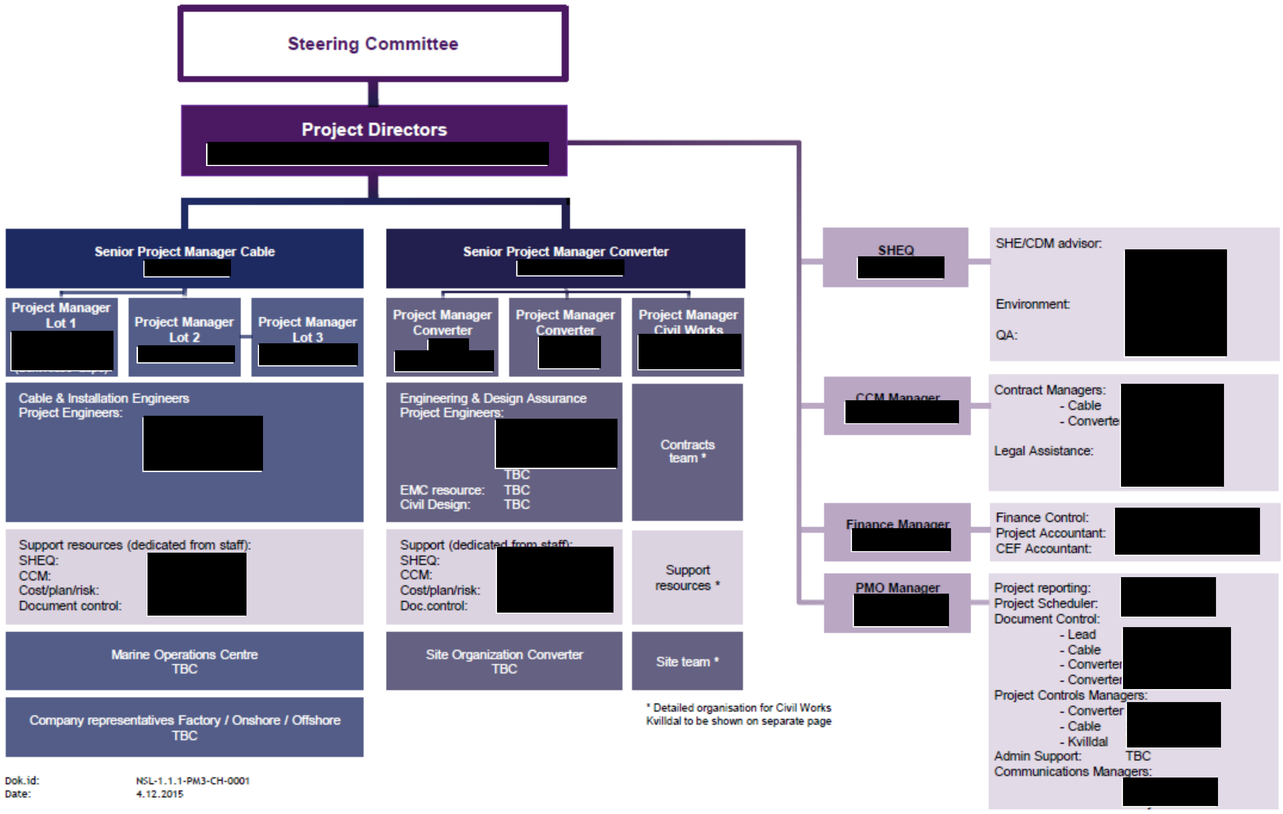
We believe that this procurement methodology and scoring is adequate in order to select the most appropriate company. Only competent companies were evaluated, with the emphasis at this point on cost to provide the maximum benefit to the consumer.

3. Developer project management

3.1. Project Organisation

The project organisational structure is given in Figure 3-1 below. The NSL submission to Ofgem states that this is a matrix structure in which those that are in functional disciplines (such as CDM, PMO and SHEQ) are also supporting cable and converter teams for operational delivery. There are two project directors with one from each company that will jointly manage the integrated team. Under certain circumstances such as an emergency or immediate operational issue, one of the two project directors will take a lead role.

Figure 3-1 Project Organisation Structure (as at December 2015)



Integration of the NGNSL and Statnett project teams takes into account the expected areas of expertise e.g. cables, converters, finance, contract management, project management and Safety, Health, Environment and Quality (SHEQ). Atkins has reviewed the CVs of key personnel and found these to provide the expected expertise and experience.

3.2. Project Management

The NSL Project Management Resource Profile (including support teams such as commercial and SHEQ) is given in Figure 3-2 below[1] and the Project Management Cost Overview is given in Figure 3-3. The following points can be noted:

- The peak number of FTEs is 94, which is reached in 2020 when two cable contractors will be installing offshore and the convertor site construction will be ongoing at Blyth and Kvilldal;
- The cumulative total cost for resourcing is [redacted] excluding contingency and infrastructure costs but including travel expenses;
- Resources continue beyond the commissioning end date due to demobilising and to ensure effective handover of the operations team;
- Statnett staff costs are 15-20% higher than NG costs due to higher living costs.

In order to benchmark and verify the NSL prediction of resources, Arup[2] and Red Penguin[3] were appointed, by the project developers, to provide two independent assessments of the project management assumptions. The scope of the Red Penguin assessment was limited to the submarine cable project management whereas Arup considered the entire project. This section will discuss the Arup and Red Penguin reports as well as the resource requirements, associated costs and the overall project management cost benchmarked against publicly available benchmarks.

[1] NSL Final Project Assessment
[2] Arup NSL Project Management Team Resource Estimate
[3] Red Penguin NSL Submarine Cable Installation Project Management

Figure 3-2 NSL Resource Profile: FTE Headcount[4]

[redacted]

Figure 3-3 Resource Profile[5]: Cost Overview

[redacted]

3.2.1. Resource requirements

3.2.1.1. Comparison of NSL, ARUP and Red Penguin resource estimates

The table below provides a comparison of the three assessments:

Table 3-1 Comparison between NSL, ARUP and Red Penguin Resourcing Estimates

	NSL	Arup	Red Penguin
Peak Resource Estimate (FTE)	[redacted]	92	
Average Resource	[redacted]	73	

[4] Kvilldall refers to site enabling and tunnelling works
[5] NSL Resource Profile

Estimate (FTE)			
Total Resource Cost (£m)	[redacted]	77.7	
Peak Offshore Resource Estimate (FTE)	[redacted]		21.4
Average Offshore Resource (FTE)	[redacted]		10.7
Total Offshore Resource Cost (£m)	[redacted]		24.1

Although we support the overall methodology and benchmarks we found that Arup's report on project management resourcing has a number of errors which should have been remedied during the quality assurance stage. Initially there appeared to be a discrepancy in the NSL Final Project Assessment report submitted to Ofgem, in which it is stated that the NSL resource cost is £10.2m lower versus the Arup spot estimate. However, the numbers presented above show a closer alignment with £3.1m difference. However the difference was later explained in terms of the travel expenses included in the NSL figures presented above but excluded from Arup's figures. Arup also provides an uncertainty estimate in which the P50 and P80 values of total resource cost are given as £74.6m and £77.4m respectively. Therefore Arup recommends a P80 contingency of £0.34m from the spot estimate of £77.7m stated within the Arup report. This does not appear to be a correct interpretation of the results. The P50 should have been stated as £70.6m with the P80 as £80.3m, therefore the P80 contingency would be £2.6m against the spot estimate.

3.2.1.2. FTE numbers

The resources associated with the PMO function are not constant across the lifetime of the project. In some areas, for example cable manufacturing during quality control inspections, Factory Acceptance Testing witnessing and cable installation supervision activities, the resources are required to be flexible and there are periods when FTE resources will peak.

As the comparison between NSL, ARUP and Red Penguin Resourcing Estimates in Table 3-1 above shows, NSL have not allowed for a peak FTE requirement for the installation of the cable. Based on the data provided within the NSL Resources Profile spreadsheet, it appears that approximately 12 FTE will be required during 2020, which is the peak of the cable installation activity. This falls short of the suggested requirement set out by Red Penguin. According to the NSL Resource Profile information provided, NSL are planning to resource the peak cable installation periods through the use of additional part time or contract resources to be sourced externally. This is an efficient way to resource a project of this scale, with the caveat that the resources will need to be available. It is important to note that these resources will be in competition with the offshore renewables industry, and therefore this presents a risk to NSL. We have not found any specific reference to this risk within the risk register provided by NSL and no mitigation proposal is provided. NSL should clarify this further.

The approaches considered by Arup and Penguin also cover the potential risk of losing resources during the project, especially during the installation phase. This is part of the uncertainty analysis that has been undertaken by Arup. Red Penguin has allowed for a larger fixed core team to help alleviate the risk of losing resources. This particular risk has been considered in the risk register provided by NSL.

3.2.1.3. FTE and consultants estimates and hourly rates

From the organisation chart, there currently appears to be 48 personnel assigned to the project from NG and Statnett which compares well to the requirement for approximately 50 FTE in Q4 2015. This will need to be increased to an average of 67 FTE and a peak of 94 FTE in summer 2020. NSL has stated that use of contractors will help to manage the peaks and troughs in resourcing.

As discussed above, we believe that NSL have resourced accordingly if drawings / designs are drip fed for review by NSL. Our opinion, based on experience gained from dealing with design reviews for offshore windfarm and substation projects, is that the review of design is likely to be required in batches with significant peaks. Typical examples of such peaks will be when the various contractors submit their designs for the cable and its installation. National Grid NSL and Statnett have stated their intention to manage these peaks through the use of external resources in the NSL resourcing documentation.

A particular concern is with the cable element, where there are three lots and there is a risk associated that each associated supplier could issue drawings / designs for review at the same time. These reviews need to be completed within tight timeframes. For a project of this type, specialist skills are required to undertake design reviews, installation supervision etc. At the same time, the specialists used to review designs and undertake installation supervision must be experienced. Since this resource pool is limited we expect that the day rates charged will be higher than those estimated in the NSL submissions to Ofgem.

Figure 3-4 below is an extract from the NSL Final Project Assessment document, page 153, showing the estimated hourly rates.

Figure 3-4 Estimated hourly rates

NG Grade description (seniority of resource)	Equivalent Statnett rate (£/hour)	NG rate (£/hour)	NG external rate (£/hour)
Director	[redacted]	[redacted]	[redacted]
Senior Manager	[redacted]	[redacted]	[redacted]
Manager	[redacted]	[redacted]	[redacted]
Specialist	[redacted]	[redacted]	[redacted]
Senior Staff	[redacted]	[redacted]	[redacted]
Junior Staff	[redacted]	[redacted]	[redacted]
Administration	[redacted]	[redacted]	[redacted]

Typical external consultancy rated for design reviews and site supervision vary between £80/hr (junior grade) for offshore survey supervision to £125/hr (senior grade) for design reviews for cable systems (based on typical fee rates for the offshore renewables industry in 2015). Equally if NSL are to recruit for full time technical resources instead of external consultants, they are likely to pay above the perceived market value.

The resourcing costs on an hourly basis estimated by Arup are higher than those which have been used by NSL. In our opinion, the hourly rates used by Arup are a more realistic view on the current resources market and suggest that the NSL estimated hourly rates have been under-estimated. In general, whilst the Arup and Red Penguin figures are close to those provided by NSL, they are higher and therefore NSL's estimate may be optimistic. There is therefore a risk to NSL that increased resource will be required, leading to increased cost.

Therefore, overall we believe that the resourcing costs estimated in NSL's submission are underestimated.

There are unlikely to be any risks associated with recruiting resources as part of the PMO team.

3.2.1.4. Post commissioning Resource requirements

It has been stated within the NSL Final Project Assessment document that resources beyond the commissioning date are required for the effective handover from the construction team over to the operations team. We agree that the PMO team is required beyond commissioning for some parts of the converter and cable work packages. In our opinion the amount of resources set aside for the cable works is high for just handover purposes. There could be other reasons why the resources have been set aside for beyond the commissioning date, such as ensuring that any snagging found during the commissioning process is dealt with by the contractors and further information in support of these should be provided by NSL. Further clarification should be sought.

3.2.1.5. Comparison with NEMO and publicly available benchmarks

BPI's report[6] supporting NEMO's cost assessment submission states that between 20 to 35 staff will be required during construction to manage the construction phase and support the business, commercial and operation aspects. This is clearly significantly lower than the NSL estimate. The Ofgem consultation document does not provide any numbers for FTEs.

[6] Consultancy support for the NEMO Interconnector, BPI, 2013

For the NEMO project, a cost of approximately £48m (in 2011 prices) was estimated for Project Management by BPI who performed the cost assessment. This is significantly lower than that estimated for NSL in absolute terms, however, it can be assumed that the offshore element would be lower due to the shorter cable length. In addition, the assessment appears to be significantly less detailed than that completed for NSL, particularly compared with the Arup assessment.

In the case of NEMO, the project management costs suggested by BPI represented 5.9% of the total capital cost. In the case of NSL the project management costs of £81.6m represents approximately 5.9% of the total project cost of £1,381m. We have compared the project management costs with PB's report for IET on Electricity Transmission costing and Western Electricity Coordinating Council's report on capital costs for electricity transmission and substation. The PB IET report earmarks between 6.2% and 9.4% for project management and project launch. WECC's report suggested an overhead of 10% of capital cost. Additionally ACER's report on Unit investment Cost Indicators for electricity transmission suggests around 10% of capital costs are attributed to project management although the latter report only considered subsea cable projects and no breakdown was provided for HVDC converter stations.

It is therefore our opinion that NSL's project management costs lie within expected ranges for a HVDC and subsea cable projects. We are however concerned that the added complexity of cable laying in deep water and over such a large distance may justify increased project management costs which have not been considered by the parent companies.

3.2.2. Project Management Plan (PMP)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[7] Project Management Plan as at November 2015

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

3.2.3. Devex Costs

The total Devex expenditure amounts to £12.2m, in 2014/15 prices[8]. These have been compared with the predicted development costs for NEMO which were estimated to be €12.7m[9]. An average 2014 exchange rate of 1.24 GBP/ Euro has been applied to enable these costs to be compared with the NSL actual costs.

Table 3-2 Comparison between NEMO and NSL Devex Costs (£/m)

	NSL	NEMO	% Difference Compared to NEMO

[8] NSL Assumption Book, page 14
[9] Cost assessment consultation for the proposed GB-Belgium interconnector, NEMO, 2014.

Employee Costs	[redacted]	1.694	[redacted]
Surveys	[redacted]	2.097	[redacted]
Consents & Permissions	[redacted]		
Land Costs	[redacted]	1.371	[redacted]
Environmental Studies	[redacted]	1.129	[redacted]
Legal	[redacted]	1.532	[redacted]
Other	[redacted]	2.419*	
Total	**12.191**	**10.242**	**19**

** May include consents and permissions*

The total Devex cost and its component parts appears to be reasonable when compared with the NEMO costs. Overall, the total is nearly 20% higher, but much of this is driven by higher surveys costs. Environmental costs are also 33% higher for NSL compared with NEMO, but again this is likely to be driven by the difference in route length.

For the NSL interconnector, the identified offshore route length is 714 km whereas the offshore route length for NEMO is 130 km. NEMO is therefore significantly shorter than NSL and it is likely that the cost difference can be explained by the shorter length.

Employee costs for NSL within the development phase are lower than for NEMO, which is surprising given NSL's larger size which suggests that NSL have benefitted from favourable rates.

4. Interconnector Capital Costs

4.1. Overall methodology and breakdown of costs

We have identified three areas of CAPEX costs from NSL's submissions to Ofgem.

- EPC Contract costs – These are the costs associated with the EPC contract conditions including all costs such as supply and installation of equipment, studies and assessments required before start of construction, spares, marine insurance, subsea crossings, contractor project management, cable materials and mobilisation and demobilisation costs, spares, civils etc.;
- Developer costs - These are costs to the owner or developer to include items such as project developer's project management and other related costs such as insurance, operational/ regulatory costs picked up by the developer;
- Additional CAPEX costs - These include costs incurred for contract variations, variations in costs due to risks materialising and/or additional options being selected by the developer. Additional CAPEX costs to the developer can also include costs such as land remediation costs, land acquisition costs, seabed lease costs etc.;
- Risk/contingency– Contingency costs not included in the EPC contracts affecting the overall project.

NSL's documentation to Ofgem included details of all the above costs. Developer costs and risk/contingency was provided as a lump sum over the project. We discussed with Ofgem possible methodologies for apportioning developer project management costs to the various elements of the contract. In order to have comparable benchmarks we were keen on aligning our methodology to that used by Ofgem.

For the purposes of this analysis the developer costs were apportioned to each contract element according to the proportion of the asset value (EPC contract costs plus additional CAPEX costs relevant to the asset) over the total capital cost of the project (total EPC contract costs plus additional CAPEX costs).

In order to apportion project risks, we used the Dovre analysis produced for NSL, inspecting each risk driver and its contribution to the calculated P70 contingency. We then allocated these contributions to the assets. Where risk drivers were relevant to the overall project, the proportional allocation methodology applied for project developer costs was used for these specific items. A further discussion on risk contingency is provided in section [0].

A summary of the costs is shown below. All costs are in 2015 prices. The exchange rates used are based on a hedging strategy carried out by NSL and is not equal to the spot trading rate on the day of contact award. More information on the hedging strategy is provided in section [0].

Project element	EPC Cost	Additional CAPEX	Project developer costs	Risk#	Total claimed costs
Cable	639	[redacted]	[redacted]	[redacted]	[redacted]
Substations and converters	280	[redacted]	[redacted]	[redacted]	[redacted]
Total	919	[redacted]	[redacted]	[redacted]	[redacted]

*Note: Additional costs have been claimed for project elements such as Overhead line and Tunnel amounting to a total of [redacted]

Note: Includes inflation for Kvilldal, Blyth and project management

4.2. Subsea Cable and Underground Cable

4.2.1. EPC Contract costs

This section compares the EPC contract costs associated with the subsea and underground cable procurement against similar information available from other projects.

Taking into account the timescales, budget and the limited number of comparable projects, a bottom up benchmarking analysis has not been conducted for this project. As the main driver of costs for cable projects is the length of cable system installed, a unit cost figure of £k/km is derived and used as the main indicator.

HVDC subsea cable projects are bespoke by their very nature and direct comparison of all contract elements is difficult unless the contract schedule of items is available, although these would be of commercially sensitive and confidential nature. Due to this we have based our assessment on signed contracted projects with relevance to NSL referring only to the EPC contract price paid by the owner to the EPC contractor.

Developer costs have not been apportioned in the figures. These have not been considered as they are not available in the public domain. The figures shown are therefore direct comparison of contracted installed capacity to be built by the EPC contractor under similar conditions.

Additional CAPEX costs have not been included. Again this reflects the bespoke nature of these projects and the unavailability of commercially sensitive data from other projects.

Where we have used publicly available benchmarks, we have attempted like for like comparison, for example by removing contingency and developer costs where the benchmarks offer enough granularity to do so.

This comparison was carried out using the currency exchange rate on the contract award date for each project, taking into account the Retail Price Index variation up to the date of the NSL Cable contract awards. Where the costs come from publicly available reports and data, the comparison uses currency exchange rate on the day or month of publication indexed to RPI up to NSL contract sign date.

In our comparison we have used mass impregnated (MI) cables only to best reflect the costs of the technology employed in the NSL project. Projects such as the recently commissioned NordBalt, 700MW, 300kV XLPE link between Sweden and Lithuania were therefore excluded. We have also included publicly available cost benchmarks such as PB's report on Electricity Transmission Costing for the IET (IET PB)10. These have also been adapted to only reflect expected contract costs. An anonymised HVDC subsea cable delivered in Ireland was also used. This is referred to as project A.

During this analysis it was clear that the benchmarked unit costs for bipole (2 cables) were significantly higher than monopole (or single cable) installations/extensions due to the additional installation, deployment, standby and risk allocation for bipole installations. It was also found that short cable sections lower than 200 km yielded significantly more expensive unit costs, presumably due to not benefitting from economies of scale. It was therefore considered prudent to exclude these groups. Figure 4-1 shows this comparison graphically. Table 4-1 below shows the comparison between the prices.

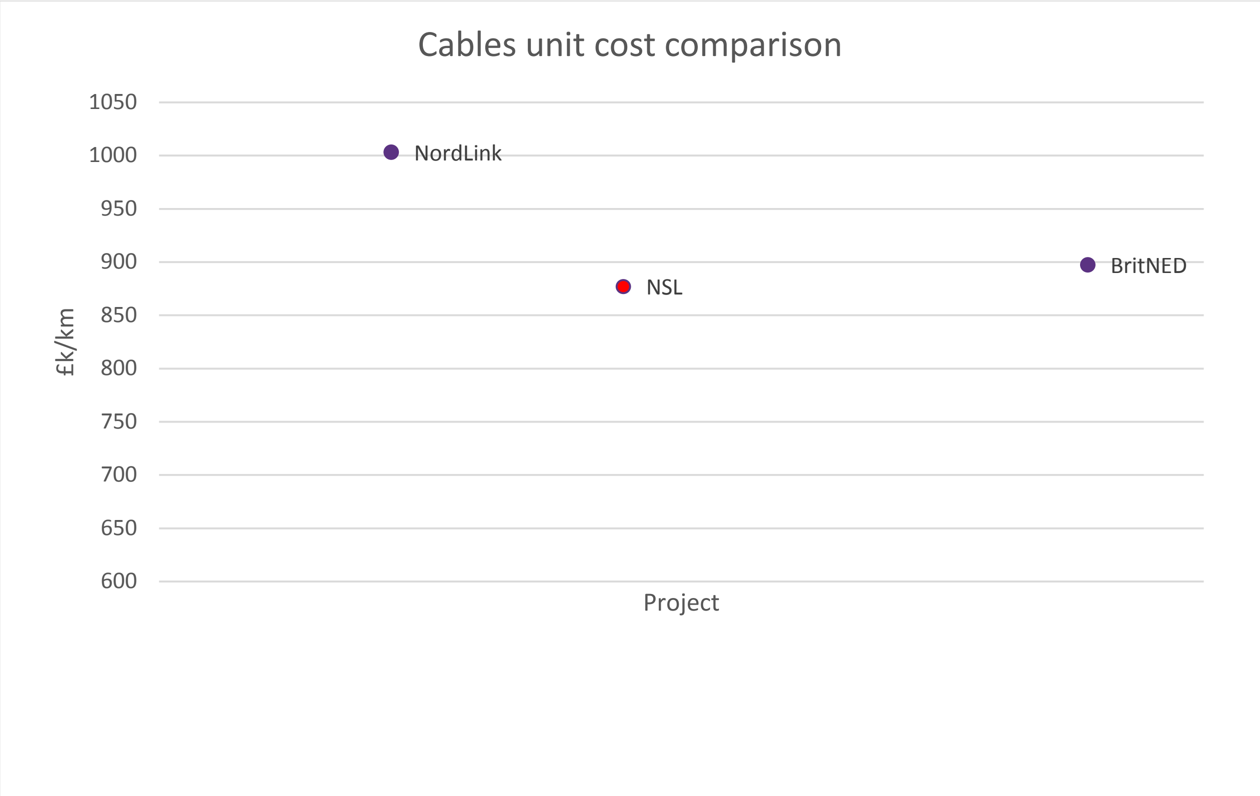
Table 4-1 Cable Cost Comparison

Project	DC Voltage (kV)	Cable Length (km)	Rating (MW)	Contract Price ('k)	Original Currency	Price in GBP (£k) (Dec 2015)	£k/km	Cable Type	Notes
NordLink	525	623	1,400	900,000	USD	625,000	1003	MI	Total cable length
NSL	525	720	1,400	[redacted]	GBP	[redacted]	[redacted]	MI	Length includes offshore) and onshore
Project	**DC**	**Cable**	**Rating**	**Contract**	**Original**	**Price in GBP**	**£k/km**		**Notes**

[10] http://www.theiet.org/factfiles/transmission-report.cfm

	Voltage (kV)	Length (km)	(MW)	Price (‘k)	Currency	(£k) (Dec 2015)		Cable Type	
Skaggerak 4 Nexans	500	140	700	87,000	Euro	61,306	437.9	MI	Offshore 140km Single Cable Only
SOBI Nexans	320	170	500	175,000	Euro	123,318	725.4	MI	Offshore only Voltage difference
Fenno-Skan 2 Nexans	500	200	800	150,000	Euro	105,700	529	MI	Single Cable Only
Italy-Montenegro Nexans	500	415	500	300,000	Euro	211,402	509	MI	Single Cable
BritNED ABB	450	259	1,000	350,000	USD	232,496	897	MI	2 cables
IET PB	320	112.5	3,000				3,570	MI/XLPE	Short section
Project A		75			EUR		3,240	MI	Short section

Figure 4-1 Cable unit costs comparison (EPC contract costs only)



This comparison shows that NSL is cheaper than NordLink and almost on par with BritNED. In our opinion given the complexity of the project in terms of length and depth of installation this suggests a favourable price for the cable contracts. NordLink is possibly the project which serves best the purpose of a direct comparison both in terms of market conditions at the time of signing the contracts and the complexity of the projects.

We are encouraged by NGNSL and Statnett's efforts to drive down contract cost of cables during the negotiations. During the course of the contract negotiations the developers have driven the costs of the cable contracts down by nearly [redacted] This is shown in Figure 4-2 provided within the submission to Ofgem.

Figure 4-2 Cable capex reduction during negotiations

[redacted]

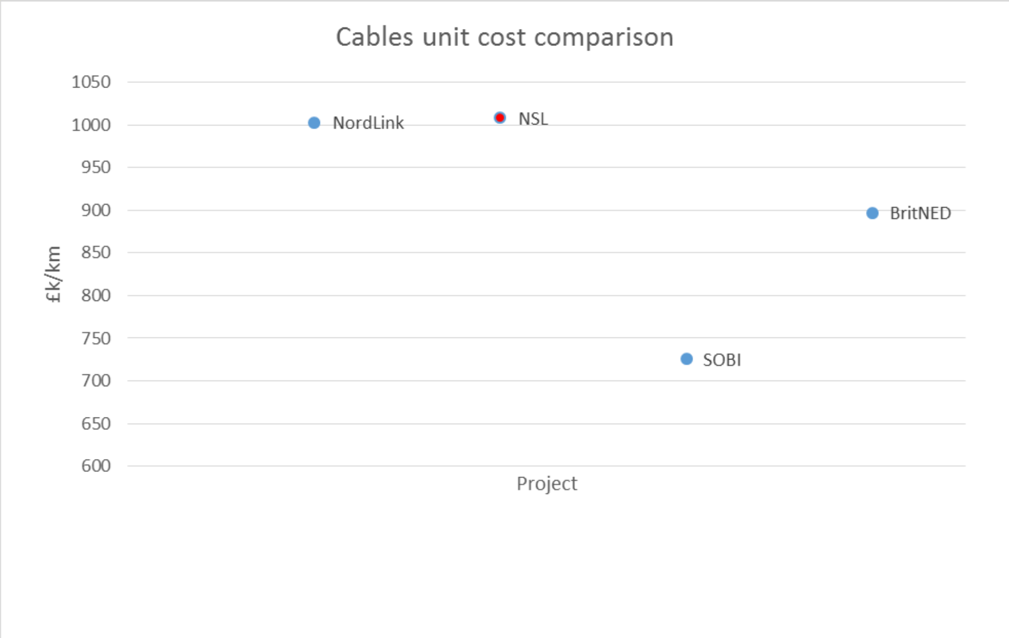
[redacted]

[redacted]

[redacted]

[redacted] It should however be noted that we are not aware of the extent of re-measurable items and/or options triggered within the NordLink contract.

Figure 4-3 Unit cost comparison with additional CAPEX costs



For this project, Atkins' scope of work does not include bottom up benchmarking. [redacted] We suggest further analysis is carried out to understand the difference in approaches.

While we agree in principle with the ex-ante nature of this assessment and the cap and floor regime, in order to allow for investment certainty, we advise that Ofgem put in place specific processes to access the information and cost changes with regards to re-measurable items during the construction phase. To protect consumers, Ofgem should also be clear in their decision the approach to dealing with re-measurable items and how the cap and floor levels will be readjusted (if at all) following confirmation of these costs.

[redacted]

[redacted]

Similar comments can be made regarding the [redacted] prices. Atkins is unsure how the cap and floor regime is expected to deal with these re-measurable items. This is an area we suggest more in-depth analysis and bottom up benchmarking is carried out.

4.3. Converter Station Costs

4.3.1. Contract costs

Taking into account the timescales, budget and the limited number of comparable projects, a bottom up benchmarking analysis has not been conducted for this project. To enable a single figure to be compared, and also to remove effects of number of poles and slightly different power ratings, a unit cost figure in £k/MW is derived and used as the main indicator.

There is only one VSC HVDC project that has been delivered at the rated voltage of 500 kV or above (Skagerrak 4). A second project in this category has been contracted with ABB to deliver a VSC HVDC project rated at 500 kV for NordLink. For benchmarking purposes we have used an anonymised 500 kV VSC HVDC project in China which has a signed contractual agreement. Since it would not be possible to derive any trends from such a small sample of projects, we have also considered a number of projects at 320 kV or 400 kV. We have included one HVDC project at 200 kV which delivers 800 MW of power although this particular project has been anonymised due to client confidentiality agreement. We have compared the contract costs with publicly available cost benchmarks such as Western Electricity Coordinating Council (WECC)11 report on capital cost for transmission and substations and PB's report on Electricity Transmission Costing for the IET (IET PB)12. As an additional data point, the IET PB report was used to calculate worst case costs based on the unfavourable market conditions. This is shown as IET PB high.

HVDC converter station projects are bespoke by their very nature, and direct comparison of all contract elements is difficult unless the contract schedule of items are available, which would be commercially sensitive and confidential in nature. Due to this we have based our assessment on signed contracted projects with relevance to NSL, referring only to the EPC contract costs. These costs were taken at the project inception when the EPC contract has been signed between the owner and the EPC provider, hence providing a reasonable comparison with the contract price in the NSL project.

Developer costs have not been apportioned in the figures. These have not been considered as they are not easily available in the public domain. The figures shown are therefore a direct comparison of contracted installed capacity to be built.

Additional CAPEX costs have also been excluded. Again this reflects the bespoke nature of these projects and the unavailability of commercially sensitive data.

Where we have used publicly available benchmarks, we have attempted like for like comparison, for example by removing contingency and developer costs where the benchmarks offer enough granularity to do so.

We have also only used, where possible, VSC converters for the comparison process. CSC converters, being an older technology, tend to be cheaper and their inclusion in these benchmarks would, in our opinion, skew the results. In terms of internationally available benchmarks, the WECC report does not split out costs for VSC and CSC/LCC. As VSC technology generally comes out at a higher £/MW than CSC, this approach is expected to show a lower unit cost. The IET PB report is therefore a better direct comparator.

This comparison was carried out using the currency exchange rate on the contract award date for each project, taking into account the Retail Price Index variation up to the date of the NSL Converter Contract award. Where the costs come from publicly available reports and data, the comparison uses currency exchange rate on the day or month of publication indexed to RPI up to NSL contract sign date. Table 4-2 shows the comparison between the prices and Figure 4-4 shows this comparison graphically.

Table 4-2 Price Comparison between Relevant Projects

[11] https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf

HYPERLINK "https://www.wecc.biz/Reliability/2014_TEPPC_

Project	DC Voltage (kV)	Rating (MW)	Contract Award/report year	Announced Original Price (Currency k)	Original Currency	Price in GBP (£k)	Price (£k) as ref date 15 Jul 2015	£k/MW	Notes
Skaggerak 4	500	700	2011	180,000	USD	111,611	107,146	153.07	Simpler project with already established converter station
NordLink	525	1,400	2015	563,767	USD	366,142	366,142	261.53	Sets market price for this type of installation, level of development and innovation
NSL	525	1,400	2015	[redacted]	SEK	[redacted]	280,865	200.62	See notes below
IET PB	320	3000	2012	565,000	GBP	565000	601,113	200.37	Excludes contingency and project management
WECC	500	1400	2014	566,944	CAD	308,984	311,764	222.69	Using WECC published data and the TEPPC calculator
HVDC A (Canada)	200	800	2014					265.06	Anonymised data
HVDC B (China)	500	1000	2012	191,900	EUR	157,799	167,885	167.89	Anonymised data
IET PB high	320	3000	2012	848,000	GBP	848,000	902,202	300.73	Reflects unfavourable market conditions such as exchange rates, metal prices etc.…

Figure 4-4 Unit cost (£m/MW) against VSC projects

[redacted]

Our analysis shows that that the price of the contract is reasonable and favourable based on a £k/MW basis when compared with the price for the above projects. This also holds true when the costs are compared with the two most comparable projects i.e. Nordlink and Skagerrrak 4, which are similar in terms of power and voltage ratings, as well as scope of work for the converter contractor. Skagerrak 4 is understandably cheaper as the works required were to extend an existing link and therefore less complex. Of the international projects and public benchmarks only HVDC B was cheaper.

Based on our assessment of the contract costs, NSL seems to have benefitted from a favourable deal for the converters, probably due to economies of scale in engineering, tooling, supply chain, etc. Some of ABB's R&D costs may also have been picked up by the prior agreed NordLink project which represents an advantage for the NSL project. However, there is a risk in that the standards required by TenneT for NordLink may differ from those required by NG/Statnett. For example, construction design management (CDM) regulations may lead to a requirement for a design change and further information should therefore be provided in terms of how ABB is dealing with this difference in standard.

While the price for the converter stations based on contracts appears to be competitive, the balance of risk and optional items versus price should be considered. We have identified a possible area where there may have been a compromise between the price of the contract and the risk of cost increase:

[redacted]

A more in depth discussion of risks and their potential consequences for the project are highlighted in section 5.

4.3.2. Overall costs

Our assessment in section 4.3.1 was based around EPC contract costs. We are however concerned that the favourable EPC costs were caused by a trade-off between contract costs, optional items and risks. We have therefore considered benchmarking the costs of NSL converter stations taking into account developer costs, additional CAPEX and associated risk values.

Comparison with available international benchmarks were more difficult in this case. Developer costs and risks are sensitive information shared between developers and regulators and/or investment providers. We have used the IET PB report, this time including contingency and developer project management and

ACER's report on unit investment cost (UIC) indicators[13] and corresponding reference values for Electricity and Gas infrastructure, which used outturn cost of projects and hence inherently took into account materialised project risks and developer project management costs. We also used WECC's cost calculator introducing an overhead level of 10% as recommended in their report.

Using these costs a similar benchmarking exercise to that carried out for section 4.3.1 was performed. These are shown in Figure 4-5 below

Project	DC Voltage (kV)	Rating (MW)	Contract Award/report year	Announced Original Price (Currency k)	Original Currency	Price in GBP (£k)	Price (£k) as ref date 15 Jul 2015	£k/MW
NSL	525	1,400	2015			[redacted]	[redacted]	[redacted]
IET PB	320	3000	2012	628300	GBP	628300	668459	£222
ACER UIC	500	1400	2015	619915	EUR	513909	513909	367
WECC	500	1400	2014	623,639	CAD	339883	342940	244
IET PB High	320	3000	2012	911300	GBP	911300	969550	323

Figure 4-5 Converter costs including developer costs and risk

[redacted]

The unit costs for NSL when developer costs, additional CAPEX and risks are included is within the middle range of the data points. It is difficult to accurately draw any conclusions from such a high level cost benchmarking exercise. However the results would suggest that NSL have benefitted from a low and favourable EPC contract costs but possibly traded off with higher risks and optional add on costs. We recommend that Ofgem commission a full in depth bottom up benchmarking exercise on the risk and additional CAPEX elements of this project to understand the values underpinning the additional CAPEX items and the P70 contingency assessment or set up barriers to UK consumers picking up excessive cost escalation due to materialised risks at project completion stage.

5. Project risks

In section 5.1 we provide a high level assessment of the risk costs submitted to Ofgem by NSL. Sections 5.2 and 5.3 highlight specific risks we have extracted based on reviews of the submitted documents and contracts and recent historical project experience, which have either not been highlighted by NSL or have insufficient mitigation in place. The risks are classified in the following areas:

- Legislative risks - contractual, subcontractor interface, H&S legislation etc.
- Technical risks – new designs, interaction with other systems etc.
- Installation related issues –equipment, ground conditions etc.

5.1. Risk

The contingency level submitted to Ofgem has been estimated using the difference between the base estimated costs and the P70 cost following a risk analysis exercise carried out by Dovre on behalf of NSL. The P70 represents that there is a 70% chance that the cost will be lower. Inputs to this assessment consisted of a minimum cost (considered as P10) and a maximum cost estimate (considered as P90) as well as the base cost estimate. During the IPA phase, Ofgem conducted assessments based on P50 values. We recommend a consistent approach and consideration of P50 costs. The difference between P50 and P70 amounts to £26m.

In order to allocate the contingencies to individual project elements we inspected each risk driver and its contribution to the calculated P70 contingency as provided by Dovre. This contribution excluding inflation for Kvilldal, Blyth and project management is shown in

Figure **5-1** below.

Figure 5-1 Contribution to P70

[redacted]

We then allocated these contributions to the relevant assets. Where risk drivers were relevant to the overall project, the proportional allocation methodology applied for project developer costs was used for these specific items i.e. 35% for converters and 65% for cables. The exchange rate used in our analysis is £1:EUR 1.35 consistent with the contractual obligations.

The total contingency including inflation amounted to [redacted]. We note that the submission for Ofgem includes a total risk contingency of [redacted] for the project. NSL need to explain the difference in costs.

The percentage of the risk element over the contract value of each element is shown below.

Project element	% (risk/element EPC cost)
Cable	[redacted]
Substations and converters	[redacted]

This high level assessment highlights our concerns about the level of risk as a proportion of the EPC contract costs, possibly suggesting a significant element of EPC contract cost savings has been passed onto the developer potential project risks. We believe a full bottom up benchmarking study of the risk registers used as input to the P70 assessment should be commissioned.

We have also analysed the risk register submitted to Ofgem by NSL. In sections 5.2 and 5.3 we describe specific project risks which have not been included in the risk register or do not have sufficient mitigation in place.

5.2. Subsea Cable and Underground Cable

Overall, in the last 5 years the severity of installation issues has reduced through the use of better specified burial and lay equipment which has refocused the onus on design, manufacture and contractor/subcontractor interface issues. Installation issues in the past have been related to untested burial equipment and burial equipment working at the limits of capability. Burial with higher specification has been tested and used on many contracts, and has meant that the reliability of the equipment and operators has increased. In the case of NSL, the major risk areas have been minimised through the use of well-established technologies and suppliers. MI cable is a mature technology and the proposed manufacturing facilities are established, therefore this type of cables has been used for a significant number of projects. In addition, the installation contractors and equipment are also established and have been used successfully on a number of previous projects under similar environmental and metocean conditions (e.g. Nexans Skagerrak vessel is being used in the Fjord section).

We have therefore focused on specific technical risks along specific interfaces which can have very significant repercussions. We have assessed the potential likelihood, severity and impact of these risks. Both cost to the developer and timescale impact have been considered. Where the risks affect the developers, the potential direct cost impact is provided using the signed contract costs as guidance. Mitigations have been suggested for the risks identified. The risks associated with the cable are given in Table 5-1.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.3. Converter Station and Civils

A simple methodology has been adopted to quantify the risks in accordance with the US DoD document, "Risk, Issue, and Opportunity Management Guide for Defence Acquisition Programs, June 2015". It consists of adopting a percentage of the contract value in line with an assumed severity level as the cost of the risk and this value is then multiplied by the probability value for each risk giving the final impact cost.

5.3.1. Contractual Risks

The converter contracts have been reviewed, and the contractual risks have been identified and described below.

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.4. Developer Costs

The risks associated with the developer costs, including project management, have been identified and summarised in Table 5-3 below.

Table 5-3 Developer Cost Risk Assessment

[redacted]

[redacted]

6. Hedging strategy

We have analysed the extract from the NSL Cost Submission for Final Project Assessment Assumptions & Data Book dated 18th December 2015 and the associated excel spreadsheet, entitled Transaction Detail Report submitted by NSL to Ofgem.

Hedging is in effect a means of insuring against future currency fluctuations; it provides greater certainty over the ability to cover future costs by taking, or retaining an option to take, currency later but at an exchange rate agreed now. There is, however, a cost associated with this process which broadly reflects the value of the certainty being purchased/the risk being transferred elsewhere.

In this deal, exchange rate risk is taken by National Grid NSL on the basis that it has substantial experience of trading globally and therefore has a developed hedging strategy. It considers that it is better value to allow suppliers to bid in their chosen currency than ask them to price in pounds. If it were to do so it would lose transparency over the cost that bidders have associated with currency exposure. This seems sensible providing that National Grid NSL limited has the expertise it claims and has developed an appropriate strategy.

The extract states 'National Grid strategy for currency is to minimise risk and maximise cost certainty through hedging exposure' which suggests that the primary driver of the strategy is risk minimisation not cost or perhaps more appropriately a balance between the two.

From the material provided it seems that as the NSL interconnector contracts were entered into National Grid NSL began the process of de-risking by entering into exchange rate purchases at spot rates: 'In order to ensure we were able to fix the GBP costs upfront and remove all currency fluctuation and risks, at contract signing NG Treasury commenced hedging the full exposure of the EPC contract through buying forward contracts for the total foreign currency amounts involved.' What the extract does not elaborate upon is why this is the most appropriate strategy versus for instance buying options which would create the right but not the obligation to take currency at the option price. A strategy focussed on the total removal of risk is very conservative.

From the material provided it is not clear whether the strategy does completely de-risk as is claimed. The contract prices themselves are not completely fixed, for instance there are re-measurable items within them which allow the initial contract price to fluctuate then the approach adopted will not remove all currency risk as is asserted here.

National Grid NSL states that the hedging process itself was undertaken over a 2 day period: 15-17 July 15. The majority of the trades fall within this period but there are a series at the end of the extract spreadsheet which have later dates. It is not clear what these are or why the dates differ; no explanation is provided.

On rates, the extract provides volumes purchased and weighted average forward rate taken. By way of example using the Euro, the rate taken ranges from £1: 1.41 euro in 2015 and 2016 to £1:1.23 euro in 2023, with an overall weighted average of £1:1.33 euro or £0.75 to the euro. The historic rate trend euro: pound as published by the European Central Bank is shown below:

Source: ECB statistical data warehouse

Overall, NG has secured a rate that sits at or around the mid-point of the range recorded over the last 16 years but at the low end of the range over the last 8; the trades span the next 8 years. It is not clear whether the rates include any associated costs and/or whether there are any additional fees associated with the strategy. It is clear that NG is working with a range of forex institutions but there is no discussion of competition for rates, although the transaction detail report includes rates from a range of institutions and transactions have been concluded with a range of banks.

We believe that overall, the approach outlined by NGNSL is conservative, perhaps overly so especially if contract prices are not fully fixed and a significant amount of re-measurable items are expected to be purchased at a later stage. One approach that has not been explored in the submission, would have been to agree an optional exchange rate for the purchase of re-measurable items but mitigate by allowing room to buy at spot price at a later stage. This is a common strategy employed by commercial companies. While it might be unreasonable to expect NGNSL to take an aggressive commercial stance the current approach does not support NGNSL's argument for total de-risking well in the material provided. Given that the regulatory regime would tend to allow for the pass through of these costs under the cap and collar mechanism, as an element of the capital cost, the approach adopted raises a question about the incentives created and whether NG takes a conservative approach because it can recover the costs and therefore has limited incentive to develop a more optimal approach to hedging.

7. Issues and recommendations

The issues and recommendations presented in this report are based on information provided at the time of writing this report (4th June 2016). We are aware that NSL are still in discussions with their contractors and will update this information. We are also aware that Ofgem will be discussing some of the issues highlighted below and will be updated with further clarifications. This section higlights areas which we believe should be discussed and updated further.

7.1. Procurement and project plan

Overall the procurement process has been found to be robust. Procurement generally seems to have been carried out in line with good practice.

However the following issues were noted and the following areas of further clarifications are required:

- The HVDC converter contracts include O&M arrangeents as options but the cost do not price these in We are therefore unaware of anymechanisms currently in place for the Operation and Maintenance Agreements. Synergies that can be developed by considering O&M arrangements as part of the overall package, for example incentives for companies to build assets that need limited maintenance or lower capital costs, have not been considered. We recommend a follow up on the reasons for this approach;
- It is not clear why NSL have agreed to deviations from the standard FIDIC contract structure and how NSL have assured themselves that the implications of these changes is fully understood. We would advise Ofgem to discuss in detail the risks to and liabilities for the developer and consider how to treat variations arising from these in terms of their impact on UK consumers;
- [redacted]

7.2. Project management

The project management plans provided were analysed. Our assessment has highlighted the following issues:

- The NSL estimate for resource costs is potentially optimistic compared with our experience as well as Arup and Red Penguin’s assessments;
- It is our opinion that NSL’s project management costs lie within expected ranges for a HVDC and subsea cable projects. We are however concerned that the added complexity of , cable laying in deep water and over such a large distance may justify increased project management costs which have not been considered by the parent companies;
- NSL estimate of resource rates appears to have been underestimated;
- In the event of an emergency or immediate operational issue, the process for determining the lead Project Director is not well defined and a process for resolution of issues for which project directors do not agree a way forward is not considered;
- NSL should ensure that the steering committee has enough technical expertise to deal with issues that arise;
- There are a number of key positions still to be filled, for example SHEQ for converters and cables. Clarification is required on how these are intended to be filled;
- NSL states that peaks and troughs will be managed through the use of contractors. The process for recruiting contractors and permanent employees, in order to give comfort that the required skills and expertise will be sourced should be provided;
- It is noted in the Project Management Plan p37 that a stakeholder management plan to cover the commencement of the construction phase will be established. This is currently not available, so confirmation should be sought that this will be produced;
- Outstanding licences, such as landowner agreements and advanced possessions, and cable crossing agreements should be sought;

- It is critical to ensure that there is a sound process for agreement of changes and for managing the associated costs in the form of a completed and robust Variation Order Procedure;
- A high level of PMO resources have been suggested for cable works post commissioning. NSL should explain their assumptions for this further.

7.3. Cable Costs

The assessment has shown that the cable EPC contract costs are in line with those expected for a project of this scale. However the following points were noted:

- As a total of the cable EPC contract costs on all three lots, [redacted]. While the cable EPC contract costs were found to be reasonable when compared with other projects such as NordLink, [redacted] we recommend a bottom up benchmarking is carried out on re-measurable items and each item individually allocated maximum capital costs;

[redacted]

7.4. Converter Costs

Based on our assessment of the EPC contract costs, NSL seems to have benefitted from a favourable deal for the converters. The unit costs for NSL when developer costs, additional CAPEX and risks are included is towards the upper end of the range of the data points. This would suggest that NSL have benefitted from low and favourable EPC contract costs but possibly traded off with higher risks. We recommend that Ofgem commission a full in depth bottom up benchmarking exercise on the risk element and additional CAPEX costs of this project to understand the values underpinning the P70 contingency assessment or set up barriers to UK consumers picking up excessive cost escalation due to materialised risks at project completion stage.

7.5. Risk Assessment

The cable and converter contracts have been assessed independently as part of the risk assessment as follows:

- NSL's contingency submission is based on the difference between a base estimate and a P70 value derived from the risk assessment carried out by Dovre on behalf of NSL. Since at IPA stage a P50 assessment was produced, we believe that for consistency a similar assessment should be carried out;
- A discrepancy of around £4m exists between Dovre's breakdown of contribution to P70 contingency including inflation [redacted] and the submitted contingency to Ofgem [redacted]. This should be clarified;-
- The level of risk contingency associated to converters and cables as a proportion of the individual EPC contract costs is high, possibly suggesting a significant element of EPC contract cost savings have been passed onto the developer potential project risks. We believe a full bottom up benchmarking study of the risk registers used as input to the P70 assessment should be commissioned. Alternatively, Ofgem should put in place specific and clear processes to access the information regarding cost escalation during the construction phase and barriers to prevent consumers being unduly exposed to these;
- Additional specific risks have been identified, and appropriate mitigations have been suggested for both the converter and cable. NSL should provide further information on how they have considered these specific risks;

- Some of the more likely and severe risks relate to the contract not being in line with FIDIC Silver, hence it is important to understand the reasons for deviation from this and whether due consideration has been given to the potential implication.

7.6. Hedging

The NSL hedging strategy has been assessed and the following issues are highlighted:

- The hedging strategy outlined by NSL is overly conservative given the amount of provisional sums to be agreed within the EPC contracts;
- Approaches such as agreeing an optional exchange rate for the purchase of re-measurable items at contract signature but allowing room to buy at spot price at a later stage do not seem to have been considered;
- Unfavourable exchange rates are possibly passed on to consumers through the CAPEX costs and therefore incentives within the cap and floor regime should be set to prevent this.

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