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Cap and Floor Regime for Regulated Electricity Interconnector Investment for application to project NEMO

Consultation

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Overview:

This consultation presents our proposals for a new regulatory regime for electricity interconnector investment for application to project NEMO, the proposed interconnector between GB and Belgium. The regime has been developed together with the Belgian Regulator CREG and will be applied on the NEMO project.

In December 2011, we outlined our preliminary conclusions on the high level principles and design of the regime. Based on these principles, Ofgem and CREG developed a proposed approach on the regime and the methodology for setting the cap and floor on returns for NEMO. In this document we outline these proposals and seek views on the proposed design and methodology.

Ofgem and CREG will consider all consultation responses with the aim of publishing a decision document by the end of 2013. This will outline our final cap and floor regime design and the methodology for setting the cap and floor on returns for the NEMO project.

Context

In GB, we currently have limited electricity interconnection capacity. There is commercial potential for further interconnection which can bring benefits to the GB market, such as market integration and the delivery of the EU internal energy market as well as security of supply benefits. The need for further cross border investment has been highlighted by the European Energy Infrastructure Package which aims to ensure that strategic energy networks are completed by 2020.

There are barriers to this investment being delivered, including: challenges with the current route in GB for delivering investment (the merchant approach); and this delivery route not being compatible with all European Member States reducing the range of candidate countries for connecting to GB. Therefore, there is a clear need to develop a regime that will overcome these barriers and develop a predictable and stable framework that will facilitate interconnector investment.

This led us to consider the development of a regulated regime for electricity interconnector investment in GB. This regime has been developed with the Belgian Regulator CREG and will be applied on the NEMO project, the proposed interconnector between GB and Belgium.

Associated documents

Electricity Interconnector Policy Consultation (12/10), January 2010: http://www.ofgem.gov.uk/Europe/Documents1/Interconnector%20policy%20consultation.pdf
Open Letter on next steps from Ofgem's consultation on electricity interconnector policy, September 2010: http://www.ofgem.gov.uk/Europe/Documents1/Ofgem%20next%20steps%20letter.pdf
Cap and floor regime for regulation of project NEMO and future subsea interconnectors (86/11), June 2011: http://www.creg.info/pdf/Opinions/2011/NEMO/Nemo-EN.pdf http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=67&refer=Europe
Preliminary conclusions of the regulatory regime for project NEMO and future subsea electricity interconnector investment, December 2011: www.ofgem.gov.uk/Europe/Documents1/Preliminary%20conclusions%20letter.pdf

Links to supplementary appendices:

Simplified financial Model Illustrating Proposed Regime Design for NEMO: http://www.ofgem.gov.uk/Europe/Documents1/Simplified%20Financial%20Model%20Illustrating%20Proposed%20Regime%20Design%20for%20NEMO.xlsx
Proposed Methodology for Setting GB Floor on Returns for NEMO: http://www.ofgem.gov.uk/Europe/Documents1/Proposed%20Methodology%20for%20Setting%20GB%20Floor%20on%20Returns%20for%20NEMO.xlsx
CEPA report: Financeability Study for Cap and Floor Regime: http://www.ofgem.gov.uk/Europe/Documents1/CEPA%20report%20-%20Financeability%20Study%20for%20Cap%20and%20Floor%20Regime.pdf
SKM report: Calculating Target Availability Figures for HVDC Interconnectors: http://www.ofgem.gov.uk/Europe/Documents1/SKM%20report%20-%20Calculating%20Target%20Availability%20Figures%20for%20HVDC%20Interconnectors.pdf
SKM model: Target Availability Model for HVDC Interconnectors: http://www.ofgem.gov.uk/Europe/Documents1/SKM%20model%20-%20Target%20Availability%20Model%20for%20HVDC%20Interconnectors.xlsx

Contents

Executive Summary

We are seeking views on our proposals for a new regulatory regime for electricity interconnector investment for application to the NEMO project, the proposed interconnector between GB and Belgium. We developed the regime together with the Belgian Regulator CREG.[1] After consultation responses have been considered, we aim to publish a decision document finalising the regime design and the methodology for setting the cap and floor on returns for NEMO before the end of 2013.

In GB, there is currently limited interconnection capacity.[2] At the same time, there is commercial potential for further interconnection which can bring benefits to the GB market, like market integration and security of supply.

Until recently, interconnector investment in GB could only be realised via the merchant approach, where developers do not receive any regulated returns on their investment, ie they face the full upside and downside risk related to the use of the interconnector. They typically seek an exemption from aspects of European legislation (eg Use of Revenues, Third Party Access[3]). However, in the case of BritNed the European Commission imposed additional conditions on the exemption decision. This was perceived by developers as an indication that the Commission sees exemptions as exceptions. It reflects the fact that in most European Member States, typically the national Transmission System Operator (TSO) invests in interconnection and often there is no merchant-exempt route available. This in turn, has limited the range of candidate countries for connection to GB.

Therefore, there is a need to develop a regime that will overcome these barriers and offer a predictable and stable framework within which investment can be made. Our proposed regime aims to facilitate economic and efficient investment, whilst maintaining a developer led approach.[4] This is because there is no central view to opine on or determine what are the optimal levels of interconnection for GB, under the current arrangements. This approach therefore aims to maintain elements of market exposure which should help to guide developers on the appropriate location, size and timing of the proposed investment and minimize exposure of consumers.

Ofgem's Integrated Transmission Planning and Regulation Project (ITPR) is currently reviewing the existing arrangements for system planning and delivery to determine whether they are appropriate to achieving a long-term efficient integrated network - onshore, offshore and cross-border. Any potential change from a developer led model to a more coordinated approach may need to be reflected in the interconnector regime design. In the shorter term and until the ITPR project is concluded, we are committed to deliver a regulatory framework for project NEMO. We are also open to consider the application of the proposed regulatory regime on other projects, whilst reserving the right to amend the regime design if that is considered necessary, for example to reflect ITPR decisions.

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[1] Commission de Régulation de l'Électricité et du Gaz.
[2] 4GW in total: 2GW to France (IFA); 1GW to the Netherlands (BritNed); 500MW to Northern Ireland (Moyle); and 500 MW to the Republic of Ireland (East West).
[3] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF
[4] Under this approach developers are responsible for the location, size and timing of the investment.

This consultation builds on the framework for the design of the regime outlined in December 2011. Based on these high level principles and the regime design, in this document we set out the rationale for our proposed design of the overall regime and the methodology to set the cap and floor on returns. This is intended to provide the necessary detail to understand the impact of our proposals.

In summary, the proposed regime is of a 20 or 25 year duration, with the levels of the cap and floor, flat in real terms, being set ex-ante and remaining fixed for the regime duration. The levels are set through a cost based approach, using a regulatory asset value model as in onshore price controls in GB and Europe, with a combination of an ex-ante opex and ex-post capex reviews. Once the interconnector becomes operational, every 5 years we would assess interconnector revenues[5] against these cap and floor values to determine whether the cap or floor is triggered. The regime also includes a symmetric financial availability incentive, linked to the cap.

The consultation also outlines our proposed methodology for setting the cap and floor on returns, which is informed by proposals from CEPA.[6] We propose to set the:

Floor on returns by tracking an index. We are seeking to allow a notionally efficient financed interconnector developer to be financeable by considering the cost of debt through the index tracked when setting floor returns.

Cap on returns by considering the cost of equity for a generation plant. Interconnectors are exposed to revenue risk between the cap and floor, impacting returns achieved. The provision of a floor on returns reduces the overall investment risk. We are seeking to reflect this reduction in risk through our choice of comparator for setting a cap on returns.

Decisions taken on the cap and floor on returns methodology are interrelated. If these are too low, the realisation of economic and efficient investment may be inhibited. Conversely, if they are too high consumers may be underwriting a larger floor than necessary and developers may receive a return that is not commensurate with the level of risk they take on. To mitigate this risk, we propose 'locking down' the returns at financial close and applying a mechanistic approach to setting the cap and floor on returns. Through this approach we are seeking to provide certainty to investors and to attract new developers to enter the market.

Finally, the consultation proposes some principles for considering the treatment of the connection process to the onshore grid in the regulatory decisions for both exempt and merchant interconnectors. It sets out the proposed timeplan for implementation of the regime on NEMO and highlights the potential that this regime could be applied to other projects beyond NEMO, subject to changes for example due to views on this consultation or due to the ITPR conclusions.

We are seeking views on the questions outlined in Chapter 2-5. Responses should be sent to cap.floor@ofgem.gov.uk by 3 May 2013.

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[5] Interconnector owners generate variable revenue by auctioning interconnector capacity. Whilst there is a price difference between the two interconnected markets, there will be demand for the capacity and a revenue stream will be generated.
[6] In October 2012, we appointed CEPA to advice on the methodology for setting the cap and floor on returns for regulated interconnectors.

1. Context: the journey so far

Chapter Summary
Outlines why we are developing a new regulatory regime for electricity interconnectors. It also outlines the regime objectives and the steps taken to date with the development of this regime before discussing the objectives of this paper.

Introduction

Why more interconnection is needed

1.1. Electricity interconnection refers to cross border transmission capacity connecting different Member States. Interconnectors derive their revenues from congestion revenues.[7] Congestion revenues are dependent on the existence of price differentials between markets at either end of the interconnector. European legislation governs how capacity is allocated. It requires all interconnection capacity to be allocated to the market via market based methods, ie auctions. It also includes specific conditions on how revenues are used.

1.2. In the European Commission's November 2012 communication on the internal market,[8] the realisation of more interconnectors in the UK was considered a priority. The GB electricity market currently has 4GW[9] of interconnector capacity. The Energy Infrastructure Package (EIP) proposed that to meet 2020 Renewable Energy Sources (RES) targets between 6-7GW is needed, and to support 80% RES by 2050 21 GW would be required. In August 2012, the Department for Energy and Climate Change (DECC) committed to further develop an evidence base on the impact on GB of different interconnection scenarios.[10] This includes further exploration of the most appropriate way of developing our interconnection capacity. This work is still ongoing.

1.3. Electricity interconnection can bring several benefits to GB. These include:

(i) Trading electricity**:** more efficient dispatch of available generation

(ii) Trading balancing energy

(iii) Provision of ancillary services

(iv) Access to non-GB reserves

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[7] Interconnectors generate revenue based on the price arbitrage opportunity between countries. Whilst there is a country price difference, there will be demand for the capacity and a revenue stream will be generated.
[8] November 2012 Communication on "Making the internal energy market work": http://ec.europa.eu/energy/gas_electricity/doc/20121115_iem_0663_en.pdf
[9] These are: IFA (2GW to France); BritNed (1GW to the Netherlands); Moyle (500MW to Northern Ireland); East West Interconnector (500MW to the Republic of Ireland).
[10] August 2012 Electricity System: Assessment of Future Challenges' https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/48549/6098-electricity-system-assessment-future-chall.pdf

1.4. These benefits need to be assessed against the costs of building and operation of the interconnection which include: fairly significant operational (opex) and capital (capex) expenditures, reinforcement costs of the onshore grid to realise the connection, losses as well as outages.

How interconnection investment is currently delivered

1.5. In general terms, there are two routes for interconnection investment: (i) a regulated route, where interconnector developers would have to comply with all aspects of European legislation on cross border electricity infrastructure and receive a regulated return for their investment (ii) a merchant-exempt route, where developers would face the full upside and downside of the investment and typically apply for an exemption from European legislation (eg Use of Revenues and Third Party Access (TPA)) in order to increase the safeguards for the business case of their investment.

1.6. Across Europe, the typical approach to interconnection is of a regulated investment. Under this approach, it is common for interconnection to be developed by the national TSO, with revenues underwritten by national transmission customers. Interconnection is considered as part of the overall Regulated Asset Base (RAB) and there is no explicit return specifically on interconnector investment.

1.7. In GB, the onshore transmission owners are prohibited from including interconnection in their RAB which would allow them to get a regulated return on any investment in interconnection assets. So, in the absence of a regulated regime, new investment in electricity interconnection can only be delivered by the merchant route, with developers seeking for an exemption from European legislation (eg from Use of Revenues requirements and TPA).

Drivers for change in regulation of new interconnector investment in GB

1.8. The merchant investment in GB has proven to be increasing challenging. In the case of BritNed, the European Commission imposed additional conditions on the exemption decision at the end of the process which involved a cap on returns.[11] Following this decision, interconnector developers communicated to us that this introduced a level of uncertainty into the exemption process, as it indicated to them that the European Commission is reluctant to grant exemptions, making it likely that additional conditions could be imposed. In addition, investors have emphasized the inherently risky nature of interconnectors (revenue risk stemming from exposure to volume and price risk) means that a cap on upside with no protection on the downside, like BritNed, reduces the attractiveness of the project.

1.9. In addition, in many European countries the national TSO cannot embark on exempt interconnector projects and they often do not allow third party investors to invest in interconnection, unless the national TSO is involved. Accordingly, it became apparent that the lack of a regulated route for investment in GB was a

[11] We understand that one of the main concerns of the European Commission was that merchant investment will be under-sized as the incentives on developers do not take into account wider social welfare benefits (ie benefits beyond those provided by economic arbitrage).

barrier for interconnection investment with countries for which the merchant-exempt route was not available.

1.10. Having different national regimes on each side of the interconnector, fully regulated and merchant, may result in asymmetric interests for the investors involved in the interconnector project, as the parties involved may not face similar construction and operational incentives. There is a clear need for a co-ordinated approach, which may not be identical in each case, but must be consistent and coherent. It is important for National Regulatory Authorities (NRAs) to be able to reach a common position and to set out a clear and predictable framework within which investment can be made.

1.11. Given the potential need to deliver more interconnection to achieve the wider social benefits of interconnection, barriers to economic and efficient investment would need to be removed. Our approach must therefore provide clear rules, whilst complying with the EU's preferred regulated approach. Consequently, there is a need to consider a regulated investment regime for non-exempt interconnectors.

Developing a regulated interconnector investment regime

1.12. The proposed regime aims to facilitate economic and efficient investment by overcoming the challenges of the merchant approach, without the use of an exemption. It aims to ensure compliance with European legislation and protect consumers from the implications of excessive revenues for developers, while ensuring that developers can earn returns that are commensurate with the levels of risk they are exposed to under the regulatory framework. As stated in the regime principles published in December 2011,[12] the regime has been designed with the intent to be open to third party investors and ensure an impartial and unbiased treatment between TSO and non-TSO developers and between existing and future developers.

1.13. The proposed regime aims to be able to facilitate the realisation of more interconnection, whilst maintaining, for now, a developer led approach. Under this approach, developers are responsible for the location, sizing and timing of the investment, because there is no central view or no body responsible for the optimal levels of interconnection under the current arrangements. It aims to maintain elements of market exposure and merchant incentives which should help to guide developers on the appropriate location, size and timing of their investment and minimize exposure of consumers.

1.14. Ofgem, through the Integrated Transmission Planning and Regulation Project (ITPR), is reviewing the existing arrangements for system planning and delivery to determine whether they are appropriate to achieving a long-term efficient integrated network - onshore, offshore and cross-border. Any potential change from a developer led model to a more coordinated approach could affect investment incentives and may need to be reflected in the interconnector regime design. However, it may be necessary in order to help us evaluate the relative merits of competing projects which is not possible under the current GB approach to system planning.

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[12] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=99&refer=Europe

1.15. In the shorter term and until the ITPR project is concluded we are committed to deliver a regulatory framework for project NEMO. We are also open to consider the application of the proposed regulatory regime on other projects. However, we may reserve the right to amend the regime design if that is considered necessary to, for example, reflect ITPR decisions.

Steps taken to date and objectives of this paper

1.16. In January 2010, Ofgem conducted a consultation[13] seeking views on options for regulating interconnection investment. The consultation aimed to address the general issue of moving from a merchant approach to a regulated model. It set out four options for consideration: i) the merchant-exempt regime, ii) a revenue cap, iii) a revenue cap and floor, and iv) fully regulated returns.[14]

1.17. Following consideration of the consultation responses, in September 2010, Ofgem and the Belgian Regulator CREG, committed to explore further the cap and floor regulated option, using project NEMO, the proposed interconnector between GB and Belgium as a pilot project.[15] The cap and floor regime was seen as the preferred approach as it had clear benefits in terms of retaining incentives for both capital and operating efficiency and availability, while ensuring compliance with European legislation, therefore removing the need for an exemption.

1.18. In June 2011, Ofgem and CREG published a consultation[16] on the principles and the basic cap and floor design. In December 2011, Ofgem published the preliminary conclusions[17] on the regime principles and design. In June 2012, Ofgem hosted a workshop to present the latest thinking on the cap and floor design and to seek views. Following this, Ofgem and CREG finalised the proposed regime design.

1.19. Ofgem and CREG proposals have been informed by two commissioned consultancy studies. Cambridge Economic Policy Associates (CEPA) advised on developing a methodology for setting the cap and floor on returns under the regime. Sinclair Knight Merz (SKM) advised on developing a methodology for calculating the target availability figures for high voltage direct current (HVDC) interconnectors. Both reports also published alongside this consultation.

1.20. In this consultation we outline our proposed cap and floor design and methodology for setting the cap and floor on returns, which will be initially applied on the project NEMO. We seek views on our proposals by 3 May 2013. Following the close of this consultation, we will take responses into account and finalise the design and cap and floor on returns methodology for NEMO. We expect to publish our final proposals on the decision on the provisional cap and floor on returns for project NEMO before the end of 2013.

[13] www.ofgem.gov.uk/Europe/Documents1/Interconnector%20policy%20consultation.pdf
[14] Chapter 3 outlines the four options for regulating electricity interconnectors: http://www.ofgem.gov.uk/Europe/Documents1/Interconnector%20policy%20consultation.pdf
[15] http://www.ofgem.gov.uk/Europe/Documents1/Ofgem%20next%20steps%20letter.pdf
[16] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=67&refer=Europe
[17] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=99&refer=Europe

2. Regime design

Chapter Summary
Outlines our proposed regime design for the cap and floor regime. These proposals build on the regime principles and high level design, set out in December 2011. For new aspects of the design, we explain the rationale of our proposals which cover three areas: parameters related to costs, revenues and incentives.

Question 1: Do you agree with our proposed regime design outlined in this chapter and Appendices 1 and 2? Is the design consistent with the high level principles established for the cap and floor regime in December 2011?
Question 2: Do you consider that provision for a financeability test within period outlined in this chapter and in Appendix 2 is needed with five year assessment periods? If so, how should the trigger point for financeability constraints be set?
Question 3: Do you consider the proposed arrangements (for market related costs and the availability incentive) incentivise high link availability?
Question 4: Do you believe that there are opportunities for gaming by developers with our proposed regime design?
Question 5: Are there aspects of the proposed regime design for NEMO that should be reviewed for future projects, eg changes in capex treatment as more of these projects are built?

Context: From principles to proposed design

2.1. Our proposed regime principles, outlined in Chapter 1, are intended to guide decisions taken on the regime design and encourage consistent evaluation for new interconnection. Guided by these principles, in December 2011 we presented our high level regime design set out in the table below:

Table 2.1: High level regime design agreed in December 2011

Aspect	Design
Regime length	20-25 years
Cap and floor levels	Levels set ex-ante and remain fixed for regime length
Setting costs	Capex – ex post capex review Opex – set ex-ante, ie before operation
Assessment period (assessing whether IC revenues are above/below cap/floor)	5 years, discrete periodic basis
Mechanism	Cap & floor returns earned within boundaries; revenues above cap returned to consumers, revenues below floor require payment from consumers (via Transmission Use of System Charges)

2.2. Project developers choose between a 20 and 25 year regime. For NEMO, the proposed duration is 25 years. The cap and floor values will be set on congestion revenues. These levels will be set ex-ante and remain fixed for the duration of the regime. This provides investor certainty on the regulatory framework applied to the project. For NEMO, an ex-post capex review and an ex-ante opex assessment will be carried out. This leaves open the possibility of introducing an incentive based approach for other projects, beyond NEMO.

2.3. Once the interconnector becomes operational, we will carry out periodic assessments to assess interconnector revenues[18] against the cap and floor values to determine if the cap or floor is triggered. We proposed discrete rather than cumulative assessments as a more transparent and simpler approach to assess performance. Revenues above the cap would be returned to consumers via the system operator (SO), who would then reduce the Transmission Network Use of System (TNUoS) charges. If revenues are below the floor then the interconnector owners would be compensated by the SO who would recover the costs by increasing TNUoS charges. National Grid would perform the SO role in GB and Elia in Belgium.

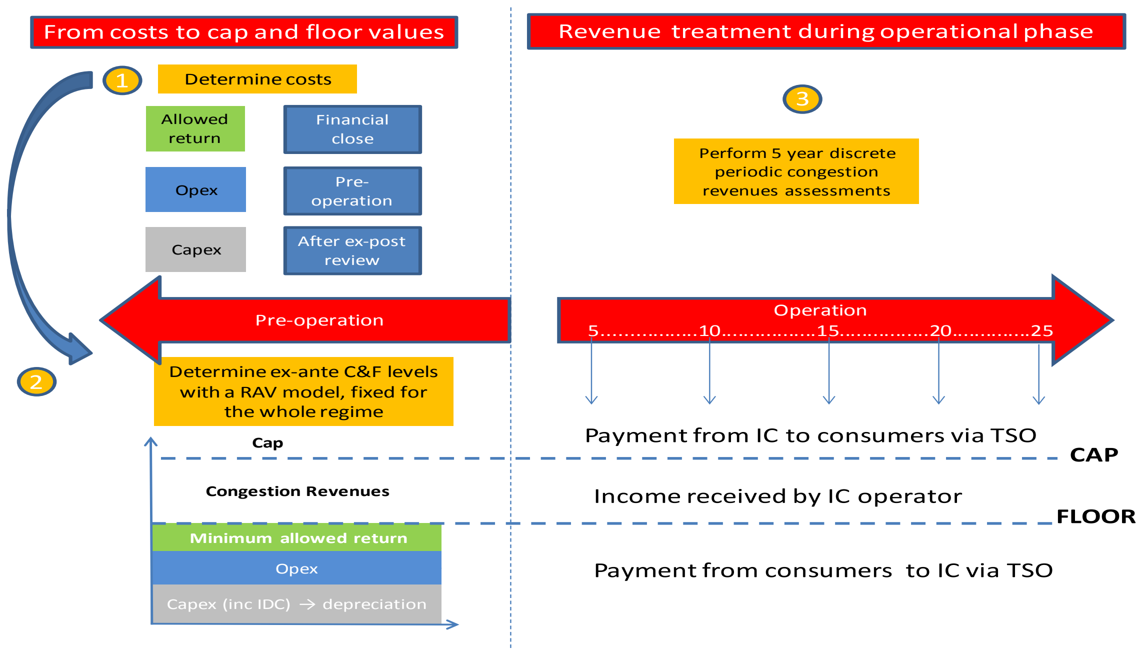
2.4. This consultation builds on the framework established for the design of the regime in December 2011. Informed by this and the high level principles for the regime, we set out the rationale for our proposals, which have been jointly agreed with CREG, for the areas of regime design previously left open. These include:

- how the level of the cap and floor will be set;
- whether any operational incentives should be introduced;
- the exact duration of the assessment periods;
- the profile of the cap and floor; and
- the methodology for setting the cap and floor returns.

2.5. Figure 2.1 summarises the entire proposed regime design. The following sections focus on the new aspects of the design which cover three areas: parameters related to costs, revenues and incentives. In each area, we outline our proposal before explaining our rationale.

[18] Interconnector owners generate revenue by auctioning interconnector capacity. Whilst there is a price difference between the two interconnected markets, there will be demand for the capacity and a revenue stream will be generated.

Figure 2.1: Proposed regime design for application to NEMO



Cost related design parameters

The role of costs

2.6. **Proposal**: Set the cap and floor values based on costs using a regulatory asset value (RAV) based model.

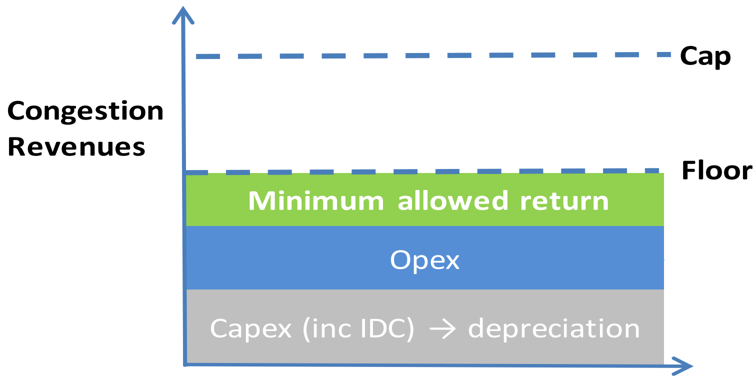
Rationale

2.7. We consider that setting the cap and floor values based on costs is simpler and more transparent than the alternative of using revenues. This approach is also consistent with onshore price controls in both GB and Belgium. Setting the cap and floor values on revenues could in theory allow us to capture the value of the interconnection in the cap and floor calculations, but it would be challenging to set these values ex-ante, given how unpredictable and volatile congestion revenues are. It would also require us providing a view on future price trends between countries where a robust and defendable judgement would be hard to reach.

2.8. A RAV model is used in most regulated sectors and is well understood by investors. For economic and efficient investment projects to be realised, developers and investors require certainty as to how the cap and floor values will be set. This is particularly important when these values are being set for the length of the regime. A RAV model is the most widely used cost based approach to set allowed revenue, including in onshore price controls in both GB and Belgium.

2.9. Figure 2.2 shows the components of a RAV model. They seek to take account of the relevant costs incurred in building and operating an interconnector link. Relevant costs can be categorised into three elements: construction costs (capital expenditure); operating costs (operating expenditure); and financing costs (regulatory return).

Figure 2.2: The components of a RAV based model



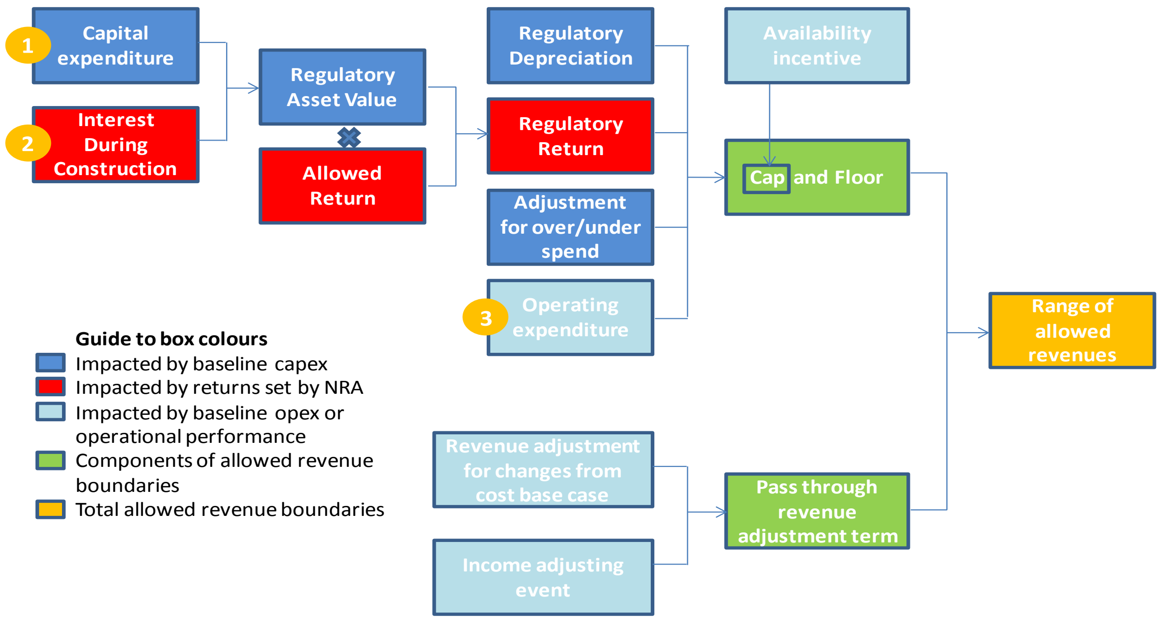
2.10. Since this is a one-off investment, capital expenditure (capex) will primarily occur during the construction phase. Since the cap and floor regime only commences when the link is operational, this capex feeds into the RAV the year it is incurred and is depreciated over the life of the asset during the regime. This is an appropriate treatment since the benefit of this capex lasts for many years. Operating expenditure (opex) is primarily incurred during the operational phase. During the operation phase, opex is incurred annually to ensure interconnector availability is maintained and any faults are repaired in a timely and efficient manner.

2.11. As shown in Figure 2.2, under a RAV model changes in the baseline level of capex and opex affect the level of cap and floor in different ways. If a higher level of baseline opex is set for a particular year of the regime, there is an equivalent increase in the level of the cap and floor for that year. If baseline capex is higher, the increase in the cap and floor will be smeared over a number of years. This is through the depreciation and regulatory return components of the cap and floor being higher.

2.12. Under our proposed RAV model, the floor allows for the recovery of economic and efficient costs for an interconnector developer. The cap and floor range, as well as the level of the cap and floor, is therefore important in providing the right balance of incentives and a risk reward trade-off.

2.13. The section below explains our proposed approach for the different components of the RAV based model, summarized in figure 2.3.

Figure 2.3: Our proposed RAV based model



1 *Capital expenditure (capex)*

2.14. **Proposal:** Use an ex-post capex assessment for NEMO to determine the opening RAV. This will be reviewed for potential use of the regime for future projects to consider whether an ex-ante incentive based approach is appropriate. All capex will be fully depreciated over the length of the regime.

Rationale

2.15. Given technology challenges, and the risk mitigation provided by the interconnectors' exposure to volume and price risk, we propose to carry out an ex-post cost capex assessment for NEMO. The alternative was an ex-ante approach.

2.16. Under an ex-ante incentive approach, which has been used in GB onshore price controls, if the outturn costs are lower than the agreed baseline then developers are allowed to keep a proportion of the gains. Conversely, if there is a cost overrun they are exposed to a proportion of these costs. This provides the regulated entities with a strong incentive to minimise costs, and outperformance results in consumers capturing some of the gains.

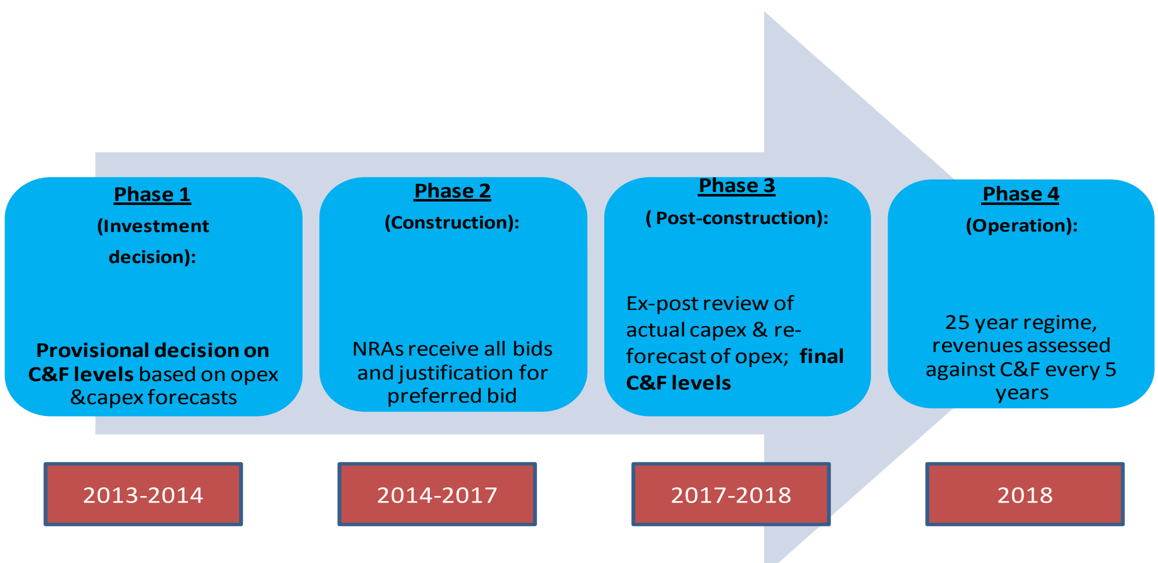
2.17. The benefits of an ex-ante incentive being realised rely on being able to arrive at a robust and defendable judgement of what the appropriate baseline (benchmark target) should be. NEMO will be built using voltage source converters (VSC) connecting into a high voltage direct current (HVDC) link. The deployment of this technology at this scale is relatively new. The lack of suitable comparators means that it would be difficult for NRAs to come up with a robust benchmark target for NEMO.

2.18. The benefits provided by an ex-ante incentive, compared to an ex-post review, are smaller for interconnectors than for regulated entities that face no volume or price risk. For interconnectors, whilst the level of the cap and floor is set on the basis of costs, project returns depend on where revenue is in relation to the cap and floor. Therefore, interconnector developers face a strong incentive to minimise costs and complete the work quickly.

2.19. For the ex-post cost assessment, we intend to follow the approach used in the GB offshore transmission regime.[19] All economic and efficiently incurred spend is passed through into the opening RAV and so into the level of the cap and floor. Any inefficient/uneconomic spend incurred is disallowed, including the associated interest during construction (IDC) true-up on this spend, discussed in paragraphs 2.32 and 2.35.

2.20. The capex forecast is updated throughout the construction phase, in line with the GB offshore regime approach. These baseline forecasts are required for the ex-post capex review. Developers would need to provide sufficient information to allow the NRAs to develop a robust baseline forecast, without which it would be challenging to determine if spend was economically and efficiently incurred for the ex-post review. We recognise that decisions taken in the construction phase could be deemed imprudent with the benefit of hindsight but based on the information available at the time of the decision and of what could be reasonably expected they may not have been. In this case, we would require that sufficient information on the rationale and the assumptions taken is provided to us in time for our assessment. Figure 2.4 shows how the capex approach feeds into the NEMO timings. We are currently in phase 1.

Figure 2.4: Timings of regulatory decisions based on the NEMO project timeplan



In **phase 1**, NRAs will make their own assessment of the proposed capex and opex forecasts based on the information submitted by the developers. Since the

[19] In December 2012, offshore transmission published a document on costs assessment guidance outlining the Authority's approach to cost assessment for offshore transmission http://www.ofgem.gov.uk/Networks/offtrans/pdc/cdr/2012/Documents1/Cost%20Assessment%20Guidance.pdf

developers are likely to run a competitive tender for some of the largest elements of capex, in **phase 2** we will update our capex estimate following receipt of this information. We will monitor closely the tender process, reviewing the developers' justification for their choice of preferred bidder, to ensure the equipment was procured economically and efficiently. In **phase 3**, we will monitor the construction phase and require the developers to report expenditure on a frequent basis. In **phase 4**, we will carry out the ex-post review, drawing on information provided in the earlier phases, making any necessary adjustment to reflect economic and efficient costs.

Other capex issues

<u>Capex treatment for potential application to future projects</u>

2.21. **<u>Proposal:</u>** Consider an ex-ante incentive-based treatment of capex for projects following NEMO.

<u>Rationale</u>

2.22. As more projects are built using this technology at this scale, producing a more robust estimate of the costs of building an interconnector may be attainable. This could enable a move towards an ex-ante incentive. We seek views on whether this would be possible and desirable.

<u>Replacement capex</u>

2.23. **<u>Proposal:</u>** Set an allowance for replacement capex up front, which would feed into the level of the cap and floor.

<u>Rationale</u>

2.24. Setting an allowance up front is consistent with the design principle of setting the level of the cap and floor ex-ante and remaining fixed for the regime length.

2.25. Some pieces of equipment on the interconnector may not last for the regime length. If they are not replaced the link may not be fully operational until the end of the regime. In this case, consumers would not receive the benefits provided by link availability and they may have to provide a top-up to the floor payment in the later years of the regime. It also introduces uncertainty for developers, which would increase the risk of the project, and hence the level of the cap and floor.

2.26. To set the allowance for replacement capex, the NRAs, will need to determine the eligible capex items that need to be replaced, the timing and magnitude of the cash flows for an economic and efficient developer. This will reflect project specific factors. Under this approach, if actual replacement capex during the regime differs from the allowed amount, the developers face full exposure to this upside/downside.

2.27. All capex will be fully depreciated at the end of the regime. If an allowance is provided for replacement capex, these replacement capex items will be fully depreciated over the remainder of the regime with the original items depreciated over the period to replacement. Straight line depreciation will be used in all cases.

2.28. Since NEMO will be built using new technology, the appropriate asset life of some pieces of capital equipment may be hard to determine. For consumers, the risk is that the allowance includes provision for items that do not need to be replaced, or can be replaced more cheaply than the forecast. This would then result in consumers potentially underwriting a higher floor than necessary. We welcome views on how to address this issue and what would be the most appropriate way to treat replacement capex.

Treatment of financial assistance

2.29. **Proposal**: Net-off grants received for the project from the RAV of the project.

Rationale

2.30. Given the potential wider social benefits of electricity interconnectors, developers may be able to secure financial aid for their project. The purpose of using a RAV model is to allow an efficient developer to recover their costs. If this developer received a grant for their project then consumers would be underwriting a potential liability, through the floor, greater than the developers' actual costs. This means all the gains from the grant would be captured by the developer.

2.31. To address this, in the case of the NEMO developers securing a grant for the project, we could net-off the grant from the opening RAV determined following the ex post capex review. This results in energy consumers underwriting a lower floor. The developer is still incentivised to obtain a grant because congestion revenue will be unaffected by the grant. A lower value of the cap and floor will mean they are more likely to be nearer the cap, and hence earn higher returns.

2.32. Finally, we also propose that when making an assessment of the financing costs for a notional efficient financed developer, the possibility of obtaining cheaper funds (eg from the European Investment Bank), should also be taken account. We seek views on how best to treat financial assistance in the regime.

2 *Interest during construction (IDC)*

2.33. **Proposal:** We will set a return (an IDC rate) that developers will earn on economically and efficiently incurred spend incurred during the construction phase of the project. A methodology will be developed to calculate this rate.

Rationale

2.34. There is a cost of financing the construction of the interconnection which is not taken account in the ex-post capex review. Industry commonly recognises this financing cost as part of capex. IDC is used to account for the delay between when costs are incurred in the construction phase and when the developer is remunerated for these (ie the commencement of the cap and floor when the link is operational).

2.35. A 'true-up' of the initial capex for IDC is therefore appropriate to ensure Net Present Value (NPV) neutrality for an efficient developer. IDC impacts the opening RAV. The higher the rate of IDC, the higher the opening RAV and the higher the level of the cap and floor, through the depreciation and regulatory return components being higher.

2.36. Paragraphs 3.44-3.50 outline how we propose to calculate the IDC rate in more detail.

3 Operating expenditure (opex)

2.37. **Proposal:** Use a two stage process will be used to set the value of opex that feeds into the cap and floor values. Set this value ex-ante for the duration of the regime.

2.38. As Figure 2.4 shows, we envisage the two stage process for determining the economic and efficient level of opex working as follows:

- In **phase 1**, NRAs make an assessment of the economic and efficient opex, which will feed into the provisional cap and floor levels decision, expected to be end of 2013 for NEMO.

- In **phase 3**, up to 12 months prior to the scheduled operational date of the link, NRAs re-assess opex forecasts submitted by developers which will then feed into final cap and floor levels.

Rationale

2.39. By updating the opex forecast closer to the operational date, the NRAs are able to set a more robust estimate of the economic and efficient costs. This is particularly important since the cap and floor values are being set for 20 or 25 years.

2.40. The economic and efficient cost feeds into the provisional levels of the cap and floor, providing greater clarity to the developer when they are taking the final investment 'go'/'no go' decision. It also protects the interests of consumers and provides developer certainty for the updated forecast. Any departures from the original cost estimates need to be fully justified by the developers. Only economic and efficient costs will be allowed in final cap and floor levels agreed in **phase 3**. This avoids consumers underwriting a higher floor than necessary whilst reducing the risk for developers.

2.41. For some elements of opex developers will have limited or no control over, eg costs imposed on them by third parties. For these cost items, it is much harder to set ex-ante a robust estimate of the economic and efficient costs for the regime length. In onshore price controls in GB and Belgium, and in GB offshore transmission, a list of pre-defined opex items is deemed non-controllable and these costs are passed through. We intend to follow a similar approach. This means that adjustments from the baseline estimate of these costs, will be treated outside the cap and floor. This is shown through the pass through revenue adjustment term in Figure 2.3. Appendix 3 provides more detail on how we propose to treat these costs.

Revenue related design parameters

Profile of the cap and floor

2.42. **Proposal:** Flat in real terms, through applying an annuity.

Rationale

2.43. We are seeking to maintain market incentives within the regulatory framework by reducing the likelihood of breaches of the cap and floor. The profile of the cap and floor affects the likelihood of congestion revenues being above or below the cap respectively. Since congestion revenues are volatile and unpredictable, adopting a neutral view by having a flat cap and floor profile in real terms seems prudent in order to achieve this aim.

2.44. On the surface the choice between a flat or declining profile and setting the cap and floor levels in real or nominal terms appear two separate questions. However, for both questions, on an NPV basis the two choices are equivalent and the impact on consumers is similar.

2.45. A flat cap and floor profile in real terms has two additional benefits:

(i) Were the regime to be used for future projects, it may facilitate economic and efficient investment, through being attractive to a wider source of investors. It is likely that institutional investors will prefer a sustained return, ie the guarantee of an inflation linked floor revenue stream, to one that is likely to diminish over time. We believe attracting a wider source of investors may be important because: interconnectors are an inherently risky business facing asset utilisation risk within the cap and floor, and this is a new regulatory regime. If a real return reduces funding costs and hence the cost of capital for these projects, consumers will benefit from underwriting a lower floor.

(ii) It reduces the need to require collateral, eg a performance bond, to be posted by the developer in the latter years of the regime when the asset is largely depreciated. Under our proposed approach of a flat cap and floor in real terms profile, the floor would be higher in later years than under the other options. Therefore, the developer would forfeit more 'floor revenue' if they walked away. We think that this approach negates the need to post such collateral, which ultimately entails a cost and would require consumers potentially underwriting a higher floor.

2.46. We are proposing that an annuity would be applied, ie re-profiling on a NPV neutral basis, to achieve the flat cap and floor profile. The annuity calculation is discussed further in paragraphs 3.51 and 3.53.

2.47. The GB offshore transmission regime recently consulted on the issue of a real or nominal revenue stream.[20] We will review our approach based on the outcome of the ongoing review to ensure consistency between the two regimes, where appropriate.

Assessment periods

2.48. **Proposal:** Every five years assess congestion revenues against the level of the cap and floor. Consider each assessment period in isolation, ie discrete periodic form of assessment.

Rationale

2.49. Five year assessments reflect a trade-off between retaining strong merchant incentives and securing finance for the realisation of economic and efficient projects, particularly by third party developers. Five year periodic assessments are also compatible with either a 20 or 25 year cap and floor regime.

2.50. The large annual volatility in congestion revenue means the cap and floor are less likely to be breached the longer the assessment period considered, as this volatility is smoothed out. A longer assessment period (instead of annual assessment) is therefore consistent with our intention of retaining market incentives within the regulatory framework.

2.51. Developers have no guaranteed revenue during an assessment period. The assessment of congestion revenues against the cap and floor values takes place at the end of the assessment period. In the intervening period, the developers need to be able to finance themselves. Lenders may be concerned by this revenue risk when evaluating the developers' ability to service its debt obligations.[21]

2.52. To cover the revenue risk within period, developers may have to obtain a larger equity buffer and/or obtain debt on more expensive terms. This could result in a higher cost of capital. In order to avoid consumers' underwriting a higher floor (due to a higher cost of capital), we propose to introduce a provision for a within period adjustment in exceptional circumstances. We provide more detail about this provision in Appendix 2.

2.53. Regarding the discrete vs. cumulative treatment of the assessment periods, we believe that consumers are expected to be indifferent between the two. The actual impact on consumers will depend on where congestion revenues are in relation to the cumulative cap and floor for the length of the regime and in each

[20] In "Offshore Electricity Transmission: Consultation on licence policy for future tenders" they presented three options for indexation: 100% indexation, the status quo; biddable indexation (since the OFTOs are appointed following a competitive tender), which is not available to interconnectors as these projects are developer-led; and partial indexation (where a fixed proportion of the revenue stream gets indexed. The consultation document is available at: http://www.ofgem.gov.uk/Networks/offtrans/et/Documents1/Offshore%20Electricity%20Transmission%20Consultation%20on%20licence%20policy%20for%20future%20tenders.pdf

[21] This risk is not present in the GB and Belgium onshore price controls, and the GB offshore transmission regime, where a guaranteed level of revenue is received each year (adjusted for performance against clearly defined incentive mechanisms).

assessment period. This cannot be known ex-ante. Accordingly, we propose to use discrete periodic assessments which are more transparent and easier to implement and allow us to reflect better merchant incentives in the regime.

Treatment of firmness & operational incentives

Firmness

2.54. **Proposal**: Firmness treated as a market related cost, and netted off from gross congestion revenues. No allowance provided in the cap and floor for these costs. Net revenues (ie gross congestion revenues minus firmness costs) assessed against the cap and floor values to determine if either has been breached.

Rationale

2.55. The value of any product is determined by its quality. Concerning transmission capacity, the quality largely depends on the level of firmness of the transmission capacity. European legislation drives the rules governing firmness and all regulated interconnectors need to comply with these rules. This, in part, drives the solution proposed of a 'partial pass through' of firmness related costs.

2.56. When the capacity is more firm, it has a higher value to market participants. When capacity comes with a low level of firmness, a market participant acquiring transmission capacity has to bear in mind that when the capacity turns out to be unavailable the developer incurs a cost. This cost can come from remedial actions, imbalance costs, missed trade opportunities, etc.

2.57. As firmness impacts the value of transmission capacity, it obviously also has a bearing on the auction revenues earned by a project developer. The auction revenues, ie the value of the capacity as perceived by the market, will be higher when more firmness guarantees are offered to the market.

If developers face the cost of full financial firmness which is desired for market participants, the project developer incurs a cost equal to the compensation of the capacity holders in the case of unavailability which could be significant. Alternatively, a full pass through of the firmness cost would potentially limit incentives to maximise interconnector availability and repair the cable in a timely and efficient manner.

2.58. We propose treating firmness as a market related cost, partially exposing developers to this cost. Under this approach, the actual auction congestion revenues can be labelled as gross congestion revenues as they represent the revenues earned by the project developer before firmness costs are taken into account. The final net congestion revenue for the project developer is the gross congestion revenue minus the market related costs. We propose that the cap and floor mechanism on revenues internalises market related costs and is set on the net congestion revenues.

2.59. We welcome views on our proposed treatment and whether other costs need to be included in this category apart from firmness.

Availability incentive

2.60. **Proposal:** An availability incentive with a symmetric financial incentive linked to the cap. We propose a 1 percentage point change in the cap for each percentage point deviation in availability from the target availability set on a project by project basis, subject to a maximum upside/downside of 2 percentage points.

Rationale

2.61. For the wider benefits of interconnection to be realised, the developer needs to be incentivised to maintain high interconnector availability and repair any outages in a timely and efficient manner at all times. An availability incentive is necessary therefore for interconnectors if the operator does not face this incentive at all times. The partial exposure to market related costs and the foregone revenue from the interconnector being down provides a strong incentive in most but not all instances.

2.62. The NRAs are concerned about the following situations arising over an assessment period:

(i) Revenue above the cap – any additional revenue earnt flows back to the TSO so the developer faces limited incentive to keep the link available;

(i) Revenue below the floor – the developer will receive floor revenue at the end of the assessment period irrespectively of how far below the floor net revenue is. Market related costs have been either partially or fully passed through to consumers in this case.

2.63. To align developers' and consumers' interests in case i), and protect the interest of consumers in case ii), we propose to introduce an availability incentive. This was supported by stakeholders at our last consultation on the regime design in June 2011.

2.64. We are proposing a symmetric financial incentive to be applied at the cap. This addresses the perverse incentive that may arise in situation i) since the cap, which net revenue is assessed against, would be adjusted, up or down.

2.65. We considered the option of applying the availability incentive to the floor as well. The floor payment aims to ensure financeability for an economic and efficient developer, with a notional financing structure, so a financial incentive tied to the floor could have a negative impact and increase the cost of capital. As a result, we are proposing no financial incentive to be applied at the floor, but the floor payment to be conditional on satisfactory level of availability. This reflects the need to protect the interest of consumers, whilst recognising that this situation could have arisen for reasons beyond the developers' control.

2.66. We are proposing to make the floor payment conditional on availability being at or above a pre-defined minimum threshold. The offshore transmission owner

(OFTO) licences seem an appropriate basis for setting these thresholds.[22] Following this approach would allow us to ensure consistency between the two regimes. If availability is below this threshold, developers' must: justify to NRAs why this situation has arisen; and demonstrate that they have taken all reasonable steps to ensure interconnector availability will be restored in a timely and efficient manner in order to receive a floor payment.

2.67. We are proposing that availability is measured over the five year assessment periods but availability is reported on an annual basis. This time horizon means the adjusted cap for the assessment period reflects the developers' operational performance over the period.

2.68. As with the GB offshore regime, we are proposing that the target availability is set on a project-by-project basis. This ensures target availability reflects project specific factors. We commissioned SKM to develop a methodology for calculating target availability for HVDC interconnectors. Alongside this document, we are publishing their report and model. This provides clarity and certainty to potential interconnector developers as to how target availability will be calculated for their projects, since their configuration can be input into the model. For the technical configuration SKM assumed plausible for NEMO, their model suggests target availability could be between 97.1% and 97.8%.[23]The actual target will reflect the technical configuration used by the NEMO developers.

2.69. Finally, since target availability is likely to vary between interconnector projects, we feel the maximum percentage uplift/reduction in the cap should be common between projects. We propose a 1 percentage point change in the cap for each percentage point deviation in availability from the target, subject to a maximum upside/downside of 2 percentage points.

2.70. We welcome views on SKM's methodology, how often the dataset should be refreshed[24] and our proposed calibration of the financial incentive around target availability.

[22] Amended Standard Condition E12-J4: Restriction of transmission revenue: Annual revenue adjustments, Part A paragraph 5 states:
"Where, in the relevant year t, the total effect and duration of all transmission service reductions, excluding those caused (in whole or in part) by an exceptional event:
(a) results in transmission system availability being, on average, below 75 % in that incentive period; or
(b) results in transmission system availability being, on average, below 80 % when considering the 24 month period of the incentive period y and the incentive period y-1;
then the licensee shall provide a written statement to the Authority, from an authorised director of the licensee, explaining how the steps the licensee has taken have discharged the obligations in paragraph 3." http://www.transmissioncapital.co.uk/projects/robinrigglicence
[23] SKM report: http://www.ofgem.gov.uk/Europe/Documents1/SKM%20report%20-%20Calculating%20Target%20Availability%20Figures%20for%20HVDC%20Interconnectors.pdf&
SKM model: http://www.ofgem.gov.uk/Europe/Documents1/SKM%20model%20-%20Target%20Availability%20Model%20for%20HVDC%20Interconnectors.xlsx
[24] SKM suggest the dataset should be refreshed on a regular basis.

3. Methodology for setting cap and floor returns

Chapter Summary
Outlines our proposed approach and methodology for setting cap and floor on returns. We explain the rationale for our proposals on key methodological considerations and our proposed methodology for setting the relevant cost of capitals for NEMO.

Question box
Question 1: Do you agree with our proposed approach on the key methodology considerations? Is our approach consistent with the high level principles established for the cap and floor regime in December 2011?
Question 2: Do you agree with our approach of using the cost of debt and equity to set returns at the floor and cap respectively, while acknowledging that that the appropriate level of the cap and floor returns are interrelated?
Question 3: Do you agree with our proposed approach to setting interest during construction (IDC) outlined in this chapter and Appendix 4? Are there any other relevant risks/factors that we should be aware of when developing an IDC methodology?

Context

3.1. In October 2012, Ofgem appointed CEPA to provide advice in relation to the development of a methodology for calculating the cap and floor to be applied to the GB electricity interconnector regime. CEPA assessed the risks of interconnector investment and then proposed what was in their view the most appropriate methodology for setting the cost of capital (CoC) for regulated interconnectors, starting with project NEMO.

3.2. CEPA's report is published alongside this consultation. In this chapter, we set out our proposed approach for setting the cap and floor on returns which is based on their proposals. We outline our views on certain key methodology considerations that need to be considered first and then we outline the proposed methodology for setting the cap and floor on returns based on the cost of capital. In the areas where we are proposing to follow a different approach than CEPA, we have explained our rationale. We also publish a model which demonstrates how the proposed regime works in practice as well as the proposed methodology for setting the GB floor on returns for NEMO. CREG was involved in discussions with CEPA and in developing our proposed methodology and has endorsed the proposals set out below. We seek views on our proposed methodology.

Key methodology considerations for cap and floor returns

3.3. There are four main methodology considerations which need to be addressed include:

(i) Weighted Average Cost of Capital (WACC) calculations for cap and floor – separate or 'central' WACC estimate

(ii) Type of approach – mechanistic or deterministic

(iii) Timing for locking down the cost of capital parameters

(iv) Cross jurisdiction issues - how to reflect them in the CoC estimates.

3.4. Below we set out the options considered under each area as well as our proposed approach.

(i) Separate WACC calculations at cap and floor or 'central' WACC estimate?

3.5. **Proposal**: Separate WACC calculations at the cap and floor.

Rationale

3.6. Separate calculations allow the different risks associated with the cap and floor to be better reflected than a single 'central' cost of capital estimate, where some parameter estimates used would reflect a compromise between the different levels at the cap and floor. The calculations can also be amended more easily, and transparently, if the regime is adjusted. Whilst this approach is more complex, the complexity is justified because it reduces the risk of setting the cap and floor on returns at the wrong level; too low – may have a negative impact on further electricity interconnector investment, too high – consumers may be underwriting a larger floor than necessary and developers may receive a return not commensurate with the level of risk they support.

(ii) A mechanistic or discretionary approach?

3.7. **Proposal**: Mechanistic approach.

Rationale

3.8. A mechanistic approach provides investor clarity and certainty which could attract new developers to enter the market. Discretion can be seen as a key element of a price control review process when there is a portfolio of existing assets. However, interconnectors differ as they are primarily a single one-off initial investment decision. In addition, the use of a mechanistic approach is consistent with how the cost of debt is calculated in onshore transmission price controls in GB.[25] We think that the benefits of a mechanistic approach outweigh the benefit of a discretionary approach which would allow an immediate response to market or unusual events but would be less transparent and could create regulatory uncertainty in the interconnector investor community.

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[25] Cost of Debt allowance in the WACC settlement under RIIO is: a 10-year trailing average of the iBoxx GBP Non-Financials indices of 10+ years to maturity, with credit ratings of broad A & broad BBB, deflated by 10-year breakeven inflation data published by the Bank of England. Cost of debt allowance is updated annually during the price control: http://www.ofgem.gov.uk/NETWORKS/TRANS/PRICECONTROLS/RIIO-T1/Pages/RIIO-T1.aspx

(iii) When to lock down the cost of capital parameters?

Proposal: Lock down CoC parameters at financial close.

Rationale

3.9. There is a trade-off between providing sufficient certainty to developers so that efficient investment is realised, ie clarity upfront required, whilst also setting a rate that reflects actual costs, ie taking a decision as late as possible.

3.10. To reflect this trade-off, we propose to finalise returns at the cap and the floor at financial close, anticipated to be 2014 for NEMO. This is when the final go/no go investment decision is taken. This provides sufficient certainty to developers to proceed with the project without exposing consumers to undue risk. Delaying the decision until construction of the asset is complete would make obtaining funding from investors more expensive. Lenders are concerned about whether the developer will be able to service the debt. Until the return at the floor is known they cannot make this judgement for certain and given the current financial climate they may not lend. Therefore, an earlier decision would work better with lender requirements. At the same time, our proposed approach will expose developers (rather than consumers) to the risk of movements on borrowing costs, who are in a better position to manage this risk.

(iv) Cross jurisdiction considerations: blended or separate calculations at each currency

3.11. **Proposal**: Blended CoC calculation, applying a 50:50 weight to the cost of capitals calculated between the two jurisdictions.

Rationale

3.12. The cap and floor regime will apply in both jurisdictions, Belgium and GB, for NEMO. The methodology needs to take account of the different market conditions, as well as currencies, in the two jurisdictions.

3.13. The developers will seek the most efficient financing solution. It therefore seems sensible to perform any cost of capital calculations on a blended basis, ie weighted, for a single cap and floor calculation rather than performing separate cap and floor calculations in each currency (ie euros and pounds for NEMO).

3.14. Since consumers in GB and Belgium will be underwriting the floor when interconnector revenues are below it, we need to establish how this potential liability should be shared between them. The blended weights could be derived from costs or revenues.

3.15. We think that costs would be more appropriate since the cap and floor is set on the basis of costs. Revenues depend on the magnitude and direction of the flows on the link which cannot be predicted with any certainty ex-ante.

3.16. Since we are setting the cap and floor ex-ante, we propose to split the costs equally between the two jurisdictions, ie apply a 50:50 weight to the cost of capitals calculated. This implies taking a neutral view on the investment decision framework. It is simple to understand and implement and provides clarity to investors, which is important particularly for a new regime, like the interconnector cap and floor.

Proposed methodology for setting the cap and floor on returns based on the cost of capitals

3.17. As outlined above, our proposed methodology includes a mechanistic approach for setting separate WACCs at the cap and the floor, which will be fixed at financial close. We propose to use the same methodology in both countries to calculate a GB and a Belgian value for NEMO returns. We then apply a 50:50 split to arrive at the value used in the cap and floor calculation. Below we set out our rationale for the four different cost of capital calculations needed for our methodology as well as our proposed approach for the treatment of refinancing gains and finance cost allowances.

Cost of Capital calculations

3.18. Under our proposed regime design, four different types of CoC calculations need to be performed, shown in Figure 3.1.

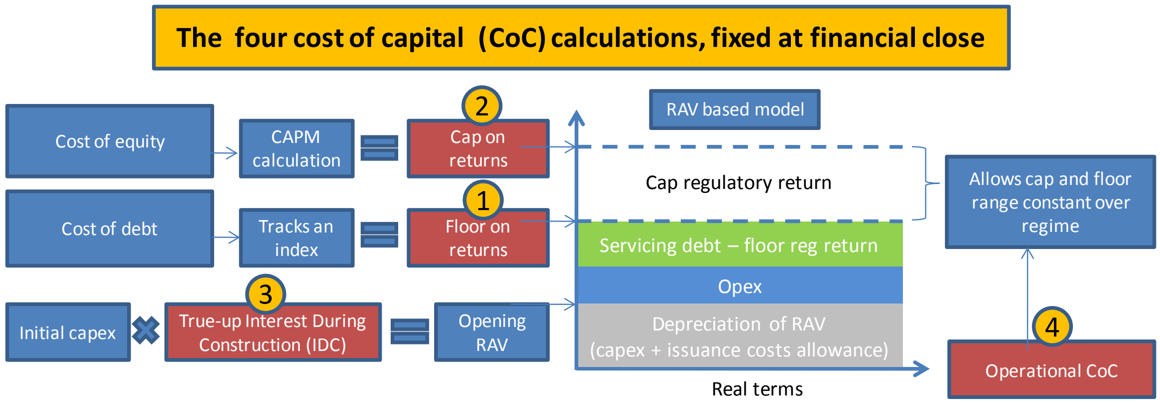
- **Calculation 1 and 2 – cap and floor returns:** In Chapter 2, we explained that the cap and floor range stems from different values of the regulatory return component under our RAV based model. This is due to us permitting different returns at the cap and floor. Since we are performing separate CoC estimates at the cap and floor, these need to be calculated.

- **Calculation 3 - IDC:** In Chapter 2, we proposed to permit interest during construction (IDC) to take account of the time delay between when costs are incurred in the construction phase and when the developer is remunerated for these (cap and floor commencement).

- **Calculation 4 – operational CoC:** In Chapter 2, we proposed that the cap and floor profile would be flat in real terms and that the five-year assessment periods would be used. To reflect the time value of money, the discount rate used to achieve this profile and deal with cap and floor breaches over an assessment period must ensure NPV neutrality.[26] Since these adjustments are taking place during the operational phase, we consider the operational CoC is the appropriate discount rate to be used.

[26] See the attached financial model for an example of how we envisage this working in practice:
http://www.ofgem.gov.uk/Europe/Documents1/Simplified%20Financial%20Model%20Illustrating%20Proposed%20Regime%20Design%20for%20NEMO.xlsx

Figure 3.1: Which, when, what cost of capital calculations.



1st CoC: Floor on Returns

3.19. **Proposed approach:** The floor should allow an efficient developer with a notional financing structure to recover their costs to ensure they are financeable. Provision in the floor for servicing debt obligations is therefore required. When setting the floor on returns the cost of debt needs to be taken into account. Tracking a cost of debt index is proposed as the mechanism for achieving this.

Rationale

3.20. Our proposed regime aims to facilitate economic and efficient interconnector investment. The floor is providing downside revenue protection for the developer and so is de-risking the project. The purpose of the floor is to ensure financeability for an efficient developer with a notional financing structure. We do not think it is appropriate for the floor to be value creating for shareholders, ie the floor on returns should not make the project commercially viable.

3.21. Under our proposed regime design, an efficient developer is able to recover their construction and operation costs through the floor. For an economic and efficient developer, the ex-post capex review for NEMO ensures actual construction costs are reflected in the level of the cap and floor. Similarly, in the operating phase, the baseline opex is derived for an economic and efficient interconnector. Under our proposed RAV based model, provision is made for a return on RAV at the floor. Some or all of the financing costs are covered in the floor return.

3.22. The cost of servicing debt obligations for a notionally efficient financed developer need to be recovered through the floor. This should be reflected in the floor on returns set. Tracking a cost of debt index to set the floor on returns is in line with our commitment to follow a mechanistic approach. It provides certainty and clarity to developers as to how the regulatory return component of the floor will be calculated.

3.23. The cost of debt will move with changes in market conditions. Tracking an index ensures developers are no worse or better off from changes in market rates in the intervening period, ie financeability is ensured whilst consumers' interests are also protected.

3.24. Under our proposal to track an index, a notional efficiently financed developer is expected to be financeable, (ie equity holders are still expected to earn a return when revenue are below the floor over an assessment period). This is because the indexed tracked to set floor returns is payable on the whole asset base, not just the geared proportion (which debt obligations apply to).

3.25. We believe a floor on returns that allows a low return for equity holders is justified for two reasons:

(i) *Debt obligations may extend beyond interest repayments* - A notionally efficient financed developer may have to abide with covenant ratios as well as covering its interest repayments. Covenant ratios are likely to be particularly important for third party investment.

(ii) *Revenue being at or below the floor may be for reasons beyond the developers' control* – for example, since an interconnector is exposed to demand risk, market conditions may mean this situation has arisen. Economic and efficient investment is unlikely to be realised if equity holders receive no return in this case. However, since the floor return is tracking a floor cost of debt index the returns will still be well below the cost of equity, so consumers' interests are still protected.

Proposed methodology:

Aspect	UK	Belgium
Use of index	20-day simple trailing average	
Index composition	**GBP** Non-Financials of 10+ years to maturity; credit ratings of broad BBB	**EUR** Non-Financials of 10+ years to maturity; credit ratings of broad BBB
Index source	iBoxx	iBoxx
Index deflator	10-year breakeven data published by the Bank of England	10-year breakeven data published by the Banque Nationale de Belgique
Return locked down	At financial close	

Rationale

3.26. A 20-day trailing average of an index reflects that interconnectors are a one-off investment and so a short time period should be considered if the floor return set is to reflect attainable cost of debt levels.

3.27. The composition of the index tracked must reflect the closest comparator(s). There are no independently listed interconnectors and so there is no direct sectoral reference point. The narrower the sector concerned, the more the value of the index will reflect sector-specific factors, rather than funding costs for a general corporate. Country specific factors, including currency denomination, also need to be taken account. By using the bespoke non-financial index, sterling denominated, used in the GB onshore price controls, which uses iBoxx data, we take account of this. For Belgium, we are proposing to adjust the constituent companies and track euro dominated issuances to take account of these country specific factors.

3.28. A BBB credit rating reflects our assessment of the risks that regulated interconnectors are exposed to under our proposed regime design. Substantial revenue risk would imply a non investment grade rating but developers are only exposed to revenue risk within the cap and floor. The floor provides a vehicle for an efficient developer with a notional financing structure to recover their costs.

3.29. Our proposed index sets a nominal floor on returns. In Chapter 2, we proposed a flat cap and floor profile set in real terms. A deflator is required to convert this nominal to a real floor on returns. Our floor on return seeks to reflect the attainable cost of debt in the market. 10-year breakeven inflation data published by the national central bank is proposed as the deflator.[27]

3.30. Alongside this consultation, we are publishing our proposed methodology for setting the GB floor on returns for NEMO. As at close of business 22 February 2013, the 20-day trailing average of the index was 1.52% real. The actual value for the GB and Belgian floor on returns will be set at financial close, with a simple average taken to set the floor on returns for the project.

2nd CoC: Cap on returns

3.31. **<u>Proposed approach</u>:** The level of cap and floor on returns should be proportionate to the level of risk the developer is exposed to. The risks at the cap should be considered together with the reduction in project risk by the provision of the floor and our proposed methodology for setting the floor on returns. To reflect these considerations, we are proposing to set the cap on returns based on the cost of equity for a generation plant.

<u>Rationale</u>

3.32. The appropriate level for the cap and floor on returns are interrelated. The higher the floor on returns the more downside revenue risk protection provided to the project. In returning for underwriting a higher floor revenue, consumers should capture more of the upside benefits. This means a lower return at the cap.

3.33. By assessing the risks at the cap and then considering the reduction in risk provided by the floor, we are in a position to develop a methodology for setting a cap on returns.

3.34. At the cap, the interconnector faces full exposure to volume and price risk. This level of risk will be influenced by changes in market and network arrangements.

[27] 10-year matches the tenure of the term to maturity of the index tracked. This deflator reflects market expectations of inflation, which may differ substantially from the central bank inflation target, and so is consistent with our intention for the floor set on returns to reflect the attainable cost of debt in the market. It is also consistent with the approach used in GB transmission for deflating the cost of debt index.

CEPA's view was that the risks faced at the cap are akin to those faced by a peaking power plant generator. Whilst we share this view, at the same time, we think that our proposed regime design means that the floor de-risks the project relative to a peaking plant generator, for three main reasons:

(i) *Less capex risk* – a peaking power plant faces full exposure to any cost overruns or delays. For an interconnector, all economic and efficiently incurred costs are passed through and provision for interest during construction (IDC) is made.

(ii) *Less opex risk* – for certain operational costs a developer will have little or no control over. The proposed provision for non-controllable costs and income adjusting events in our regime, outlined in Appendix 3, reduces the potential large liability for interconnectors for unexpected events.

(iii) *Provision of floor revenue* – the operational risk is significantly reduced by the provision of floor revenue. A peaking generator does not have this revenue security.

3.35. Therefore, we believe that a generator company is a more suitable comparator, to reflect that developers are still exposed to revenue risk whilst the floor reduces cost risk and provides downside revenue risk protection.

3.36. At the cap, we are setting the maximum upside potential of the project. Economic and efficient interconnector investment will be realised, if for a notionally financed developer, equity holders can earn a rate of return at the cap above the project cost of equity, given that shareholders' wealth is then increased. Since we are carrying out separate Cost of Capital calculations at the cap and floor, it is appropriate to apply the cost of equity computed on the whole asset base not just the non-geared proportion (ie the returns at the cap for equity holders would be above the cost of equity).

Proposed methodology:

Aspect	UK	Belgium
Calculation technique	Capital asset pricing model (CAPM)	
Risk free rate	Long-term real risk free rate used in recent regulatory settlement – 2%	Long-term estimate of the real yield on long-term Belgian OLO (linear bonds) since Belgium joined the Euro – 2.0%"
Equity beta	2-year asset beta of Drax, 50% notional gearing	
Equity risk premium	Latest UK value of arithmetic mean from Dimson, Marsh and Staunton (DMS), which is published in the Credit Suisse Global Investment Returns Sourcebook, for the data series starting in 1900	Latest Belgium value of arithmetic mean from Dimson, Marsh and Staunton (DMS), which is published in the Credit Suisse Global Investment Returns Sourcebook, for the data series starting in 1900
Return locked down	At financial close	

Rationale

3.37. The CAPM is the most widely used model to calculate the cost of equity. This provides certainty and clarity to developers as to how the regulatory return component of the cap on returns will be calculated. Under the CAPM, the cost of equity is equal to the risk-free rate plus the product of the equity beta and the equity risk premium.

3.38. We propose to use CEPA's point estimate of 2% real for the long-term risk free rate used as it is based on recent UK regulatory settlements on the cost of equity. This reflects the long term investment horizon of equity investors when financing these projects since it is a 20 or 25 year regime.

3.39. Following our assessment that a generation stock is the most suitable comparator for setting the cost of equity, we propose to use Drax as a comparator. Drax is the only UK independently listed generation stock and to calculate an equity beta, the movement between the stock(s) considered and the market is required.

3.40. We are proposing to take the two year daily returns rolling equity beta (vs. FTSE 100). For much of 2011 and 2012, Drax has had negative gearing, ie more cash and short term investment than loans, which has meant the asset beta has been higher than the equity beta. This asset beta needs to be adjusted for our notional gearing assumption during the operational phase of the project (what the cap and floor returns methodology is based on).

3.41. We propose using a 50% notional gearing. The floor provides for the recovery of economic and efficient costs. Would this be the only factor to be considered, the notional gearing would be higher than 50%, as the risks at the floor are similar to a transmission company and they have higher notional gearing (60% for NGET and 67% for Elia in their latest price control settlements). However, the floor payment is only guaranteed every 5 years, rather than every year with an onshore price control, so a larger equity buffer or higher cost of debt is required to cover this cost of carry. The cap and floor is also a new untested regulatory regime whereas the onshore transmission regime is well understood by investors. Obtaining more debt finance and/or debt on cheaper terms will be easier for an onshore transmission company than an interconnector. Given these two factors a 50% notional gearing appears appropriate.

3.42. The equity risk premium is the premium demand by investors from investing in the market portfolio as opposed to the risk-free investment (in our case bonds). It is the expected return rather than a guaranteed return. A long-term data series is considered, since 1900, to smooth out some of the volatility in actual returns. The use of an arithmetic mean results in a higher equity risk premium and hence cost of equity than a geometric mean. Arithmetic means are typically used when evaluating project cash flows. We believe an arithmetic regime appears appropriate since interconnector investment is developer led.

3.43. As at the end of 2012, using the latest data for the equity risk premium, the cap return for the GB end of the link would be 8.40% in real terms. The actual value for the GB and Belgian cap on returns will be set at financial close, with a simple average taken to set the cap on returns for the project.

3rd CoC: Interest during construction (IDC)

3.44. **Proposed approach:** Apply a similar approach to the IDC calculation in the GB offshore transmission regime. Aspects of the methodology may be amended to reflect the risks faced by interconnectors under the proposed regulatory regime design may be different than the GB offshore transmission regime.

Rationale

3.45. Our aim is to set the IDC rate at a level that an efficient interconnector developer ought to incur during the construction phase. This ensures that on a NPV basis, a notionally efficient financed developer is no worse or better off from the delay between when costs are incurred in the construction phase and when they are remunerated for these(ie the commencement of the cap and floor).

3.46. There are three options for calculating the applicable rate of IDC:

(i) Apply the prevailing cap on IDC in the GB offshore transmission regime (currently 8.5% nominal, pre-tax)

(ii) Apply a similar approach to the IDC calculation in the GB offshore transmission regime. Aspects of the methodology to reflect the risks faced by interconnectors under the proposed regulatory regime design being different.

(iii) Develop a new methodology for calculating IDC.

3.47. For NEMO, since the cap and floor regime will apply at both ends of the links, option i) does not provide a robust and defendable basis for calculating the applicable rate of IDC in Belgium.

3.48. CEPA advocated option iii) and proposed their own calculation. We do not agree with the need for a 'risk of unrewarded costs' (RoUC) term which is used to cover: severe delays due to technology or unexpected events; and/or cost over-runs, as an ex-post cost review of capex is being carried out.

3.49. Option ii) is our preferred approach as the risks are broadly similar between the two regimes. In both cases, the construction phase is being considered in isolation. The capex risk is broadly equivalent as the regulatory regime is the same, an ex-post assessment is being carried out in both cases. We propose to use a methodology that is based on the GB offshore transmission calculation but adapted to reflect inherent differences between the two regimes.

3.50. In Appendix 4, we outline the similarities and differences between this regime and the GB offshore transmission regime to assess the relative level of risk. We welcome views on this assessment. This could provide the basis for developing a methodology. We intend to outline the methodology for setting the IDC rate alongside the publication of our decision document, later this year.

4th CoC: Operational cost of capital

3.51. **Proposed approach:** We propose to take the cap and floor on returns as the cost of equity and cost of debt respectively for the project. We intend to use a 50% notional gearing to set the operational cost of capital.

Rationale

3.52. Our proposed methodology for setting the cap and floor on returns considered the interconnector in the operational phase only, as IDC is used for the construction phase. The methodology calculates the cost of equity and debt respectively for a notionally financed interconnector. The operational CoC should therefore be the weighted average of the two based on the assumed notional gearing. We propose that this assumed notional gearing should be 50% for reasons justified in our methodology for the cap, described in paragraph 3.41.

3.53. This is a departure from CEPA's approach to calculating this CoC. They proposed re-estimating the cost of debt and equity. We believe the operational cost of debt and equity computed at the cap and floor respectively, are appropriate inputs to the operational CoC calculation. This approach also ensures consistency in all CoC calculations for the methodology.

Treatment of refinancing gains

3.54. **Proposal:** If the developer is able to secure a refinancing gain we are minded to allow them to keep all of the gains. We will review our approach based on the outcome of the GB offshore transmission regime review. [28]

Rationale

3.55. We are minded-to allow the developer to keep any refinancing gains for two reasons:

- **Our proposed CoC methodology implicitly factors in refinancing.** Under our proposed approach, we are considering the construction and operation phases in isolation when calculating CoC for these two phases of the project for a notionally efficient financed developer. IDC reflects the CoC during the construction phase whilst the methodology for setting the cap and floor on returns considers purely the operational phase. As a result, within the cap and floor calculation we are clawing back the likely refinancing gains associated with moving to the operational phase. This manifests itself in consumers' underwriting a lower floor.

- **Consumers are underwriting floor revenues but not necessarily providing this.** Unlike the GB offshore transmission regime, energy consumers are only making a direct contribution to the cost of the project if the floor has been breached. This makes the case for consumers to share any of the refinancing gains, typical with many public project finance initiative (PFI) projects, much smaller. Since we have captured the main source of refinancing gains from a reduction in the risk profile in the above we consider we are protecting consumers' interests through this approach.

Separate finance cost allowances for developers

3.56. **Proposal:** Provide an allowance for debt and equity transaction costs expressed as a percentage of the opening RAV. This will be added to the opening RAV. We are proposing to set returns on a vanilla basis[29], and to set a separate tax allowance at the cap and floor to take account of this.

Rationale

3.57. The methodology for setting the regulatory return component of the level of the cap and floor, focused on calculating the cost of equity and debt respectively. The two other finance costs taken into account in onshore transmission price controls when reaching regulatory settlements are transaction costs and a tax allowance.

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[28] http://www.ofgem.gov.uk/Networks/offtrans/et/Documents1/Offshore%20Electricity%20Transmission%20Consultation%20on%20licence%20policy%20for%20future%20tenders.pdf.

[29] A vanilla return is a weighted average of the post-tax return on equity, ie after corporation tax, and the pre-tax return on debt, ie before tax is paid by the debt holders. In other words it excludes all tax-related matters from the cost of capital calculations.

3.58. Transaction costs are either incorporated within the cost of capital settlement or an allowance given separately. The two approaches are equivalent on an NPV basis but by providing an allowance in the RAV it means that our proposed methodology for setting the cap and floor on returns is clearer to understand.

3.59. Normally a separate computation is done for tax costs. This is because capex allowances and interest repayments are tax deductible. We are proposing to set returns on a vanilla basis, and to set a separate tax allowance at the cap and floor to take account of this, to avoid developers' receiving a windfall gain.

3.60. In Appendix 5, we set out our rationale for our proposals in these areas.

4. Implications of our proposed design and cap and floor return methodology

Chapter Summary
Looks at the implications for investors of our proposed methodology for setting the cap and floor returns. We do this in order to check whether our regime principles are achieved under our proposals.

Question box
Question 1: Is our analysis on Return on Regulated Equity (RoRE) considerations consistent with the high level regime principles?
Question 2: Do you think that our proposed RoRE range is sufficiently wide enough to retain market incentives within a regulatory framework?

Context

4.1. One commonly used measure of looking at how companies are performing is return on equity (RoE). RoE is the amount of net income returned as a percentage of shareholder equity. It measures a corporation's profitability by how much profit a company generates with the money shareholders have invested. RoE is useful for comparing the profitability of a company to that of other firms in the same industry.

4.2. In order to evaluate the impact of financial incentives under our price control proposals for onshore regulated networks, Ofgem developed the return on regulated equity (RoRE) metric. Since we want to perform a similar exercise for our cap and floor proposals, RoRE is a useful metric for us too. RoRE is the financial return achieved by shareholders in a licensee, (in our case the interconnector owner), during a price control period (20 or 25 years under the cap and floor regime), from its outturn performance. The return is measured using out-turn income and cost and is expressed as a percentage of (share) equity in the business.

Return on regulated equity analysis

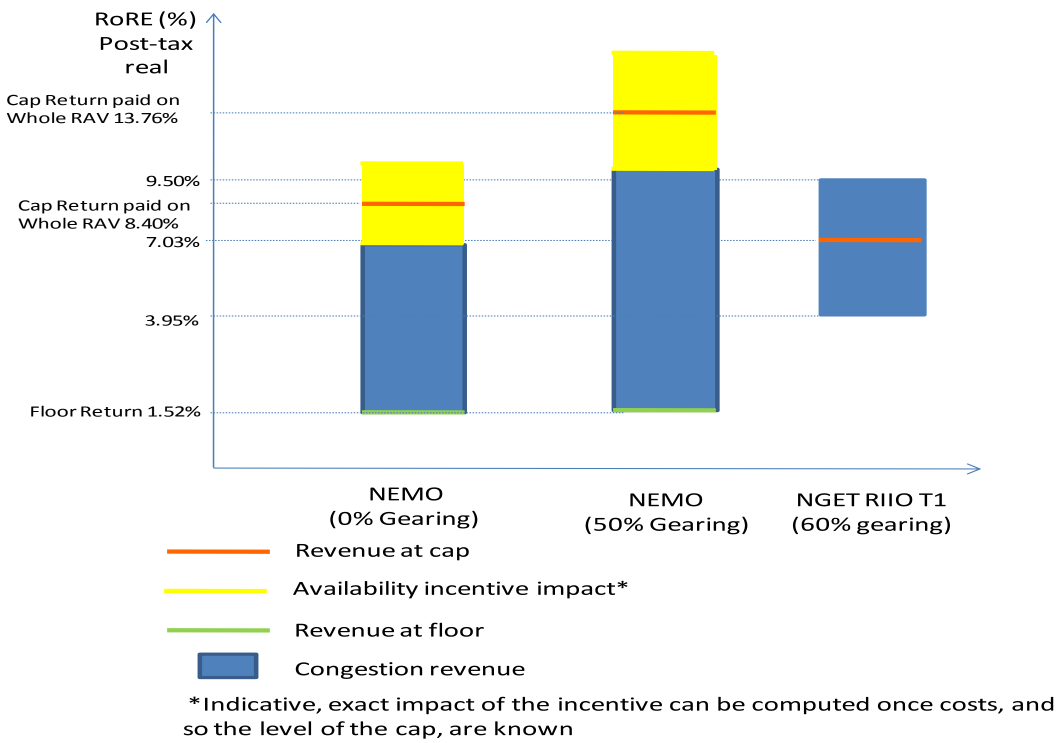
4.3. Typically, the gearing and cost of debt figures used are those given as the 'assumed' levels in the relevant price control final proposals. The aim of the RoRE measure is to provide an indication of the return achieved by the owners of a licensee whose out-turn costs are in line with the allowance provided. This can then be compared to the cost of equity originally allowed in the price control settlement and to the return achieved by other licensees on an equivalent basis.

4.4. For a given level of congestion revenue and performance against financial incentives, RoRE may differ from RoE as the latter will be affected by actual financing structure, out-turn costs in relation to the baseline forecast, and the cost of debt respectively. Since we are evaluating the impact of our proposals for a notionally financed interconnector developer our analysis focuses on RoRE.

4.5. Unlike onshore price controls, where notional gearing is set for the duration of a price control, the gearing level for a notionally efficient financed developer will decrease during the cap and floor regime. This reflects the fact that interconnectors are a one-off investment and so the debt will be repaid over the course of the regime. This results in RoRE being dynamic over the length of the regime whereas it is static for an onshore price control. Since our RoRE analysis needs to take account of this, in Figure 4.1 we show the RoRE range under our assumed operational gearing (the 50% gearing bar) and when all the debt has been paid (the 0% gearing bar) to illustrate the two extremes.

4.6. For our notionally financed interconnector developer, the plausible RoRE range under our proposed regulatory regime is shown in Figure 4.1. Four factors determine this range outlined below.

Figure 4.1: Indicative RoRE ranges under our proposed regulatory regime based on values of GB cap and floor returns methodology[30]:



(i)Floor returns

4.7. Our floor returns methodology is the 'assumed' cost of debt for our notionally financed interconnector developer. This return is paid on the whole RAV, not just the geared proportion. If congestion revenue is at or below the floor, the developers will earn this return independent of the gearing. The current value of the floor returns under our proposed methodology is 1.52%. This represents the current lower bound on RoRE.

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[30] At close of business 22 February 2013 for floor return and close of business 31 Dec 2012 for cap return.

(ii)Cap returns

4.8. Our cap returns methodology is the 'assumed' cost of equity for a generation company. Since this return is paid on the whole RAV, not just the equity proportion in the assumed financing structure, the RoRE associated with congestion revenue being at or above the cap will be at a minimum the cap returns. This arises if there is no gearing in the 'assumed' financing structure, the left hand bar in Figure 4.1.

(iii)Gearing

4.9. If the 'assumed' financing structure has gearing, the RoRE associated with revenue being at or above the cap will be higher than the cap returns. This is because the developer is receiving the cap returns on the whole RAV but is only paying floor returns on the cost of debt. Under the values of the cap and floor returns used in Figure 4.1, they are receiving a return of 8.40% but only having to pay 1.52% on the geared proportion. These savings are then distributed to equity holders increasing their return. This is why the RoRE upside increases with gearing. As explained earlier gearing has no impact on the RoRE downside as we are applying floor returns on the whole RAV, not just the geared proportion.

(iv)Availability incentive

4.10. We are proposing a symmetric financial incentive tied to the cap. This moves the revenue cap up (down) for out (under) performance on availability vs. the target availability. This is depicted by the adjusted revenue cap in figure 4.1.

4.11. Once the interconnector developers have covered their costs the residual can be distributed to equity holders. RoRE therefore increases when congestion revenue are nearer the cap than the floor. The impact of the downside of the availability incentive is a reduction in the maximum upside on RoRE. It has no impact on the developer if congestion revenue is below this adjusted cap. Overall, the larger the financial incentive tied to the availability incentive the greater the upside potential for RoRE.

A sense check of our RoRE range

4.12. Having computed a RoRE range under our proposals, we compare these against those on offer in other regulatory regimes and for other relevant comparators. This is because there are competing sources for investors' funds. Debt and equity investors will make their decision based on their assessment of the returns on offer and the associated risk.

Floor return

4.13. Under our proposed regime design, the risks faced by the interconnector developer are similar to those of a transmission company. It is therefore helpful to compare the lower bound of plausible RoRE ranges under our proposals with those in onshore transmission price control settlements.

4.14. For the latest price control settlement for National Grid Electricity Transmission (NGET), RIIO-T1, equity holders will earn a return on RoRE of 7.0%

under the assumed financing structure.[31] Since the onshore transmission company is not exposed to any revenue risk, the baseline RoRE is the cost of equity set in the price control. The presence of financial incentives on various output measures have the same impact as the availability incentive for regulated interconnectors; namely, they drive the plausible RoRE range.

4.15. Under the same assumptions, if interconnector revenue is at or below the floor, the lower bound on RoRE (ie the floor return) will be below the onshore transmission level. The cap and floor regime aims to maintain market incentives. Accordingly, the purpose of the floor is to ensure that the link is financeable for economic and efficient investment, but it is not designed to be value creating for shareholders. If revenue is continually below the floor, then equity investors should receive very low returns.

4.16. In addition, the financial incentives structure of onshore price controls translates poor performance into reduced RoRE for onshore transmission companies as they will earn a lower RoRE than the cost of equity (7.0% for NGET RIIO-T1) set in the price control settlement. It is therefore appropriate to compare the lower bound of the interconnector RoRE with the lower bound on RoRE for onshore transmission companies when financial incentives are included. As stated by Ofgem in the initial proposals for the RIIO price controls,[32] our intention is that companies should be exposed to a downside return on (notional) equity at or below the cost of debt. Since the index used to set the floor on returns for interconnectors, seeks to track the cost of debt, our lower bound on RoRE is consistent with the onshore approach.

Cap return

4.17. For an interconnector, revenue at or above the cap equates to a baseline RoRE at or above the upper bound on RoRE (assuming 25% gearing[33]) for a high performing transmission company under GB price control settlements. In addition, the symmetric financial incentive tied to the cap for availability, can increase the upper bound on RoRE significantly above this level.

4.18. As discussed in Chapter 3, we feel that the upside attainable should be similar to those expected for a generation plant. We believe this provides a sufficient upside for investors for economic and efficient interconnector investment to be realised.

4.19. We welcome views on our analysis.

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[31] Assuming there is no out or under performance on financial incentives.
[32] http://www.ofgem.gov.uk/Networks/Trans/PriceControls/RIIO-T1/ConRes/Documents1/RIIO%20T1I%20NGGT%20and%20NGET%20Finance.pdf
[33] The 25% gearing assumption corresponds to when half the debt has been repaid for a notionally efficient financed developer during the operational phase. As explained in paragraph 4.5, this reflects the fact that interconnectors are a one-off investment and so the debt will be repaid over the course of the regime.

5. Interconnector investment regime: wider issues and next steps

Chapter Summary
Outlines our emerging thinking on the principles for reflecting how the connection agreement feeds into regulatory decisions on the investment framework. We also outline the expected timing for regulatory decisions on NEMO and discuss the potential application of the cap and floor regime for projects following NEMO.

Question 1: Do you agree with the proposed for considering the connection process in the regulatory decisions on electricity interconnector investment? Are there any other areas that need to be considered in the principles?
Question 2: Do you have any views on the regulatory decision making process for project NEMO and on any other areas of consideration for the cap and floor regime beyond NEMO?

Context

5.1. This chapter covers wider issues related to interconnector investment, beyond the cap and floor regime design and methodology on returns. It sets out our views on the proposed treatment of interconnection when it comes to connection issues to the GB grid. On this area, we felt it would be appropriate to set out our views for both regulated and merchant-exempt interconnectors, as connection issues are relevant for both types of investment. In this chapter we also outline our proposed approach for taking regulatory decisions on project NEMO, in line with the developers' timeplan for construction and operation of the cable. Finally, we also set out our views on how we might envisage the cap and floor regime, following decisions on NEMO. We welcome views on these areas.

Treatment of interconnection to the GB grid

5.2. Under the developer led approach, interconnector developers are responsible for deciding the location, size and timing of their investment proposal. Regarding their connection to the onshore grid, projects are considered on a first come first served basis, based on the connection application timing. This approach worked well under the previous merchant-exempt route, where developers faced the full downside and upside of the investment and TNUoS charges reflected the costs imposed of connecting to different parts of the network. The recent removal of TNUoS charges from interconnectors means that this financial signal no longer exists. In addition, the implementation of the Third Package clarifies that interconnectors should be treated as transmission, rather than generation or demand. As a result, interconnector owners have the responsibilities of TSOs and have a duty to consider an economic efficient and coordinated solution for the project and for the wider GB transmission grid.

5.3. These changes have created a clear need to consider how the connection process and the wider reinforcement costs required to realise a connection would be reflected in the regulatory decisions under both the merchant-exempt approach and the evolving regulated cap and floor approach.

5.4. As discussed in Chapter 1, the ITPR project may bring changes to system planning and the developer led approach. In the interim, it is important to establish some high level principles of how the connection process will feed into the regulatory decisions for electricity interconnector investment. This will ensure that the development of further interconnection is not disrupted, prior to the ITPR project being completed.

5.5. Below we set out our preliminary thinking on these high level principles. They are not intended to describe the connection process but to reflect how the connection agreement feeds into regulatory decisions on the investment framework.

- National Grid and the interconnector developer applying for a connection to the GB grid should cooperate and coordinate to deliver an economic and efficient connection for the project and the GB system as a whole, at the least cost to GB consumers. Both parties should also cooperate with the remote end TSO to ensure an efficient solution is reached.

- Ofgem will expect to receive appropriate information from the two parties on the agreed connection location and the wider reinforcement costs needed to realise this investment. This should demonstrate why the agreed location is the most economic and efficient, providing a cost benefit analysis comparing this location to other options considered. This should be accompanied by a clear timeplan for implementation and delivery of any works needed for this particular location and the cost implications for developers and GB consumers.

- In order to ensure that the interests of consumers are protected, only costs incurred to realise an economic and efficient connection location would be considered in the regulatory decisions for interconnector investment. This means that any additional costs that are not justified (eg inefficient onshore reinforcement or constraint costs) may result in Ofgem rejecting or imposing additional conditions on the exemption decision for a merchant-exempt project or would be disallowed from the RAV under the regulated route.

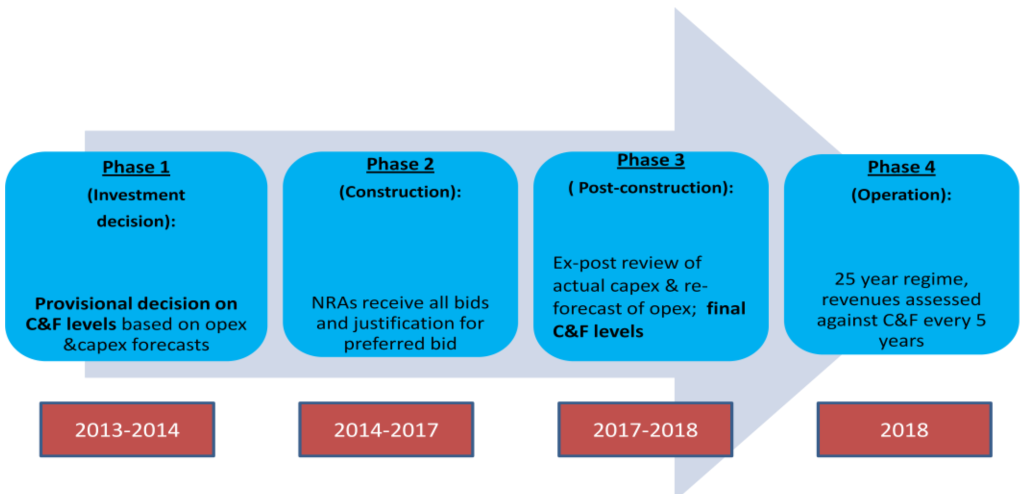
- Ofgem will only be in a position to take a decision on the regulatory framework of the project once a connection offer has been signed. This means that in the case of exemptions, an application will only be considered complete once a solution has been agreed between the two parties. Equally, for the regulated regime we will only be in a position to consider the application of the cap and floor regime on the project, when we are notified that a connection agreement has been signed and we have received all the relevant information, set out above.

- Until the ITPR project concludes, interconnector investment proposals will continue to be treated on a first come first served basis. Where two or more projects apply for a connection at a similar time (eg with a 0-3 months timelag), National Grid would need to ensure that it has an appropriate process to consider the projects simultaneously or to use the 'interactive offers' process, in line with the principles that apply for interactive generator applications.[34]

5.6. We seek views on our initial thinking on the principles that should drive how the connection process feeds into regulatory decisions on the electricity interconnector investment framework. After this consultation has been concluded, National Grid will take into account responses and establish an interim process for connection applications, before ITPR is in place. We would expect NGET to consult the relevant stakeholders on the proposed approach in a timely manner.

Regulatory decisions on project NEMO

Figure 5.1 Project NEMO timeplan and regulatory decisions



5.7. Figure 5.1. illustrates the different phases of regulatory decisions for project NEMO and how these fit with the proposed plan of developers for construction and operation of the cable. Following consultation, we will consider responses and finalise the regime design and proposed methodology for setting the cap and floor returns on NEMO. The timing for us to finalise the regime will depend on views on our proposals. In 2013, we intend to conduct our own independent assessment of the economic and efficient capex and opex forecasts for project NEMO. We would expect to publish our final proposals on the design and our proposals on the **provisional cap and floor returns** on project NEMO before the end of 2013. This is in line with the NEMO project timing, where final investment decisions are expected at the same timeframe.

5.8. Once the regime is finalised we would expect to initiate a licensing review (interconnector as well National Grid's transmission licenses) in order to allow for the implementation of the regime.

[34] http://www.nationalgrid.com/NR/rdonlyres/C27D5BF3-1EDA-4A13-9BD7-A4E96BC02B86/53731/CUSC_Section_6_CMP200_V121_15May2013.pdf
http://www.nationalgrid.com/NR/rdonlyres/4FED5DC4-7707-460F-9FE9-BB1C57C80B4A/46926/PolicyDocumentforManagingInteractiveOffers.pdf

5.9. In 2014, we expect to review the tender process and seek for justification from developers of the preferred bid which will then be used as an updated capex estimate.

5.10. In 2017-2018, post construction of the link (exact timing would depend on project developers) we would expect to conduct our own ex-post capex review and request an updated opex forecast from developers which we would also assess independently to come up with our view on the economic and efficient opex and capex. We would then expect to take a final decision on efficient and economic projects costs and make any necessary adjustments to **the final cap and floor levels**.

5.11. Once the cable becomes operational (2018 for NEMO), we would expect to request annual reporting of revenues, costs and availability and conduct our periodic 5 year assessments to see whether the cap and floor is triggered.

Cap and floor regime beyond NEMO

5.12. We intend to develop a regulatory regime that would be potentially applied on other projects beyond NEMO. We have already engaged in discussions with developers interested in investing via the regulated cap and floor regime and we are open to continue these discussions and to initiate discussions on new proposals. However, before opening up the process for implementation on other projects, we will first (a) conclude the regime design and (b) take a decision on the provisional cap and floor level for NEMO.

5.13. At the same time, we also need to take into account the developments under the ITPR project which may bring changes to system planning and delivery that could affect investment incentives. From an interconnector investment perspective some changes to the current approach may be inevitable. Moving from a merchant to a regulated approach requires us to have a view on how much interconnection capacity would be efficient, given that consumers would be underwriting part of the investment. As explained in our first chapter, at the moment there is no process for us to evaluate projects simultaneously as there is no central view on either the preferred locations or the size of interconnection that would be needed from a system planning perspective.

5.14. We therefore reserve the right to make further changes in the regulatory regime initiated either for example from views on this consultation regarding the regime design beyond NEMO or from the conclusions of ITPR project on system planning and project delivery.

5.15. It is important to highlight that we remain open to consider exemption applications for investors who prefer this route. The exemption criteria and process are set out in the EU Electricity Regulation[35]. From our side we are committed to work closely with the fellow NRA on the other side of the border to establish a joint regulatory approach as well as with the European Commission, which is the ultimate decision making body on exemptions applications.

[35] Article 17: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0015:0035:EN:PDF

6. Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 3 May 2013 and should be sent to:

- Emmanouela Angelidaki and Phil Cope
- European Electricity Transmission
- 9 Millbank, London, Ofgem, SW1P 3GE
- Telephone number: +44 207 901 7037, (7491)
- Cap.Floor@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, we will finalise the regime design and proposed methodology for setting the cap and floor returns on NEMO. The timing for us to finalise the regime will depend on stakeholder views on our proposals. During this time, we will conduct our own independent assessment of the economic and efficient capex and opex forecasts for project NEMO. We would expect to publish our final proposals on the design and our proposals on the provisional cap and floor returns on project NEMO before the end of 2013. Any questions on this document should, in the first instance, be directed to:

- Phil Cope
- European Electricity Transmission
- 9 Millbank, London, Ofgem, SW1P 3GE
- Telephone number: +44 207 901 7491
- Cap.Floor@ofgem.gov.uk

CHAPTER: Two

Question 1: Do you agree with our proposed regime design outlined in this chapter and Appendices 1 and 2? Is the design consistent with the high level principles established for the cap and floor regime in December 2011?
Question 2: Do you consider that provision for a financeability test within period outlined in this chapter and in Appendix 2 is needed with five year assessment periods? If so, how should the trigger point for financeability constraints be set?
Question 3: Do you consider the proposed arrangements (for market related costs and the availability incentive) incentivise high link availability?
Question 4: Do you believe that there are opportunities for gaming by developers with our proposed regime design?
Question 5: Are there aspects of the proposed regime design for NEMO that should be reviewed for future projects, eg changes in capex treatment as more of these projects are built?

CHAPTER: Three

Question 1: Do you agree with our proposed approach on the key methodology considerations? Is our approach consistent with the high level principles established for the cap and floor regime in December 2011?
Question 2: Do you agree with our approach of using the cost of debt and equity to set returns at the floor and cap respectively, while acknowledging that that the appropriate level of the cap and floor returns are interrelated?
Question 3: Do you agree with our proposed approach to setting interest during construction (IDC) outlined in this chapter and Appendix 4? Are there any other relevant risks/factors that we should be aware of when developing an IDC methodology?

CHAPTER: Four

Question 1: Is our analysis on Return on Regulated Equity (RoRE) considerations consistent with the high level regime principles?
Question 2: Do you think that our proposed RoRE range is sufficiently wide enough to retain market incentives within a regulatory framework?

CHAPTER: Five

Question 1: Do you agree with the proposed high level principles for considering the connection process in the regulatory decisions on electricity interconnector investment? Are there any other areas that need to be considered in the principles?
Question 2: Do you have any views on the regulatory decision making process for project NEMO and on any other areas of consideration for the cap and floor regime beyond NEMO?

Appendix 2 - Assessment periods and financeability test

2.1. Appendix 2 outlines the rationale for our proposal to introduce a provision for a financiability test within the assessment periods which was set out in Chapter 2.

2.2. Congestion revenue earnt during an assessment period is compared against the levels of the cap and floor to determine if the cap and floor has been breached. The duration of the assessment period will affect the likelihood of the cap and floor being breached.

2.3 In Chapter 2, we set out our proposed approach of five year assessment periods to reflect competing pressures. To cover this longer period of revenue risk, developers will either have to have a larger equity buffer and/or obtain debt on more expensive terms. This results in a higher cost of capital and consumers underwriting a larger floor for the project. It could also be a barrier to third party investment. Five year assessment periods, where 100% of revenue is at risk during the assessment period, presents a larger financing challenge, particularly to non-TSO investment.

2.4. The national TSOs are able to use their balance sheet (corporate finance) to finance the investment. This finance is backed, either through an explicit parent company guarantee or an implicit guarantee, such that if the project fails lenders will be recompensed. By contrast, third party developers are likely to use project finance (bank debt or bonds tied to the project) which is non-recourse. Given the current impaired capital markets and more stringent capital requirements for banks annual covenant ratios are likely to be imposed by lenders. The regime aims to be finance solution invariant. Therefore, third party interconnector investment should be able to meet the capital requirements necessary for project finance.

2.5. To address this, we are proposing to introduce a provision for a financeability test: within the assessment period. This will allow us to maintain the benefits of five year assessment periods without prohibiting efficient investment from being delivered. Lenders' main concerns are around debt servicing. This downside risk would be mitigated to some extent by allowing an adjustment within period in exceptional circumstances, reducing the cost of capital and facilitating access to finance.

2.6. The developer would need to demonstrate that the cash flow shortfall from being below the cumulative floor for an assessment period has occurred for reasons beyond their control.

2.7. We propose that as with onshore price controls, this financeability provision should not cover developers who have adopted highly aggressive gearing assumptions and may become unable to service their debt. The trigger point for financeability constraints is likely to be below the cumulative floor.

2.8. We welcome views on our proposal and also on how the trigger point for financeability constraints should be set.

Appendix 3 – Pass through revenue adjustment term

3.1 This appendix outlines in more detail our proposed approach for the costs that developers have limited or no control which was set out briefly in Chapter 2 and illustrated in figure 2.3. It outlines the rationale behind the main categories of the pass through revenues adjustment term: (i) revenue adjustment for changes from the cost base case and (ii) the income adjusting event.

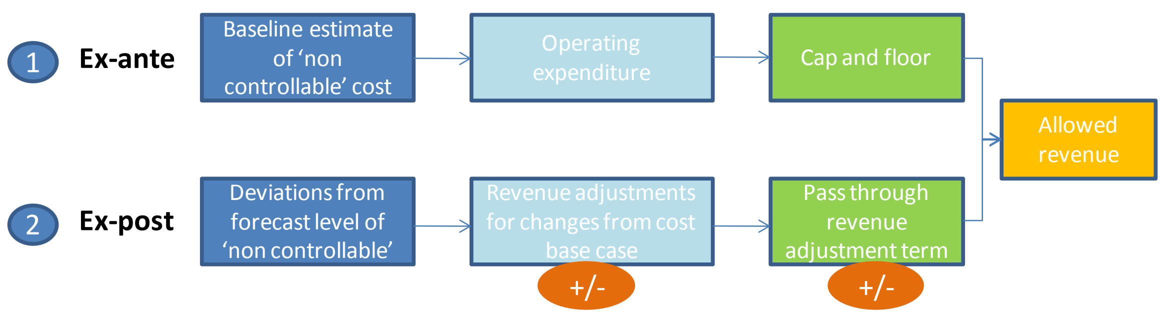
(i)Revenue Adjustment for changes from the cost base case

3.2. In onshore price controls, the concept of non-controllable costs is used for cost items that regulated network companies have little or no control over and whose costings are hard to predict. These costs are passed through outside the price control to the transmission owner. In the GB offshore transmission regime, these costs are passed through under the pass-through revenue adjustment term.

3.3. We are proposing to introduce such a category for this regulatory regime. The baseline estimate of these 'non-controllable' costs will be included as operating expenditure in the cap and floor.

3.4. For these costs, developers are not exposed to deviations from the baseline estimate. These deviations could be either upwards or downwards. The "revenue adjustment for changes from cost base case" term, deals with this circumstance. Our proposals are summarised in Figure A3.1.

Figure A3.1: Treatment of 'non-controllable' costs in a cap and floor regime



3.5. In the case of the "revenue adjustment for changes from cost base case" term being positive, the developer must show that they have done all they could to limit the increase for each cost item with a positive deviation (outturn > baseline). This may be limited, due to the nature of the eligible cost items covered under the 'non-controllable' heading. However, only economic and efficient costs will be passed through into the pass through revenue adjustment term.

Cost items considered under the revenue adjustment term

3.6. The proposed eligible cost items covered under the "revenue adjustment for changes from cost base case" are based on the GB offshore transmission regime.[36] We propose the "revenue adjustment for changes from costs base case" (R_t) would be:

$R_t = \Delta CEL_t + \Delta PR_t + \Delta DC_t + \Delta LF_t + \Delta GC_t + \Delta MCA_t$

Where:

Δ is the difference between the baseline estimate and the outturn cost

CEL_t = Crown Estate Lease

PR_t = Property rates/taxes

DC_t = Decommissioning cost

LF_t = Licence fee

GC_t = Grid costs

MCA_t = Marine and Coastal Act 2009

3.7. The two excluded items from the offshore transmission licence are the tender fee cost adjustment term and temporary physical disconnection term as these are not applicable to interconnectors under this regime.

3.8. It is worth noting that full provision for these baseline decommissioning costs is provided over the regime. This is in line with the approach followed in the GB offshore regime. Making full provision for these costs during this regime, reflected in a higher cap and floor, was required because there is no relevant legislation for decommissioning in GB.

3.9. The set of assumptions behind this baseline cost estimate may change due to legislation changes or requirements by the relevant authorities (eg The Crown Estate and the Marine Management Office in GB). In this case the increase/decrease in the economic and efficient costs is passed through outside the cap and floor, ie it is a non controllable cost. Otherwise, developers are exposed to the full cost upside/downside.

(ii)Income adjustment event

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[36] In the GB offshore transmission licence, "Amended Standard Condition E12-J3: Restriction of transmission revenue: Allowed pass-through items" lists the allowed pass-through items for an OFTO: http://www.transmissioncapital.co.uk/projects/robinrigglicence.

3.10. For any change in operation cost items not listed in the R_t term in paragraph 1.9, the criteria for an income adjusting event would have to be met. The GB offshore transmission licence provides a helpful definition of an income adjusting event:[37]

(i) "an event or circumstance constituting force majeure under the STC; or
(ii) an event or circumstance resulting from an amendment to the STC not allowed for when allowed transmission owner revenues of the licensee were determined for the relevant year t; or
(iii) an event or circumstance other than listed above which, in the opinion of the Authority, is an income adjusting event and is approved by it as such in accordance with paragraph 21 of this licence condition"

3.11. As the regime is trying to retain market incentives within a regulatory framework, and provision has been made through the R_t term, the NRAs believe the income adjusting event threshold should be set reasonably high.

3.12. There is a high regulatory burden associated with investigating these claims and developers should be incentivised to focus on minimising costs. However, having no provision for an unforeseen liability increases the risk of the project and hence the cost of capital.

3.13. We are minded to set the threshold for the cost associated with the claim as 5% of the floor in real terms. The capex/opex split will vary between projects. Tying the threshold to the amount consumers are underwriting through the floor reflects the impact of the cash flow risks to the developer.

3.14. Both the income adjusting event and eligible 'non controllable' costs terms feed into the level of the 'pass through revenue adjustment' term. In both cases, only the economic and efficient spend is being passed through, which may be less then the increase sought by the developer. The NRAs do not envisage any income adjusting events within the cap and floor regime.

3.15. In terms of the timing of the adjustments, this is a timing of cash flow issue, as on a NPV basis the two are equivalent. Making the adjustment at the next available opportunity reduces the risk for developers and so the cost of capital and hence the floor that consumers are underwriting. As this approach is consistent with onshore and offshore transmission regimes across Europe we are minded to follow this framework. In practice, the next available opportunity may involve a two year time delay from the income adjusting event happening.

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[37] From, "Amended Standard Condition E12-J3: Restriction of transmission revenue: Allowed pass-through items" lists the allowed pass-through items for an OFTO: http://www.transmissioncapital.co.uk/projects/robinrigglicence.

Appendix 4 – Interest during construction

4.1. Appendix 4 provides a qualitative assessment of the relative level of risks faced by developers in constructing transmission assets in the GB offshore transmission regime compared to the cap and floor regulatory regime. In Chapter 3, we proposed to set a return (an IDC rate) that developers will earn on economically and efficiently incurred spend incurred during the construction phase of the project. We are proposing to develop a methodology to calculate this rate based on that used in the GB offshore transmission regime, where a cap on IDC is set. The level of risk impacts the required return for a notionally financed developer. This annex compares the risk during the construction phase of the project between the two regimes in four areas:

(i) The type of regulatory regime

(ii) The complexity involved in constructing transmission links

(iii) The impact of transmission construction spend on project returns

(iv) The security provided to lenders and the availability of capital

4.2. We provide our initial assessment in each area before discussing how this assessment may inform decisions taken on how we develop the methodology to calculate the IDC rate for an efficient interconnector developer.

(i)The type of regulatory regime

4.3. **Assessment:** The risks associated with the interconnector and the offshore transmission regimes are very similar.

Rationale

4.4. In both regimes, all economic and efficient spend is passed through into the final transfer value (for offshore) and the opening RAV (for interconnectors) in the ex-post cost assessment. This is a weaker capex incentive than an ex-ante sharing factor, typically used in onshore transmission, and so both regimes have a reduced level of construction risk.

4.5. When reaching its decision on the applicable IDC rate for an efficient OFTO (offshore) and an efficient interconnector developer (this regime), the NRA is considering the construction phase in isolation when reaching its decision.

4.6. In the offshore regime, IDC is being applied to obtain the final transfer value, the value the successful OFTO pays for the transmission assets in the generator build option that, to date, has been adopted. The successful OFTO was appointed through a competitive tender to run and operate the links for the 20-year regime. There is a clear delineation between the construction and operational phases.

4.7. For interconnectors, the methodology used to set cap and floor returns is for the operational phase only. IDC is being applied to obtain the opening RAV and stops being payable when the link is operational, the commencement of the cap and floor.[38]

(ii)The complexity involved in constructing transmission links

4.8. **Assessment:** Interconnectors are more risky than offshore transmission but the level of risk may converge over time.

<u>Rationale</u>

4.9. Interconnectors under the cap and floor regime are generally expected to be built with new technology, voltage source converters (VSC) connecting into a high voltage direct current (HVDC). To date, the transmission links for most offshore wind farms have been built using established technology, high voltage alternating current (HVAC). This is due to the shorter distance of the cables.

4.10. As offshore wind farms are built further from shore, we are likely to see more HVDC transmission links. As more projects are built with this type of technology, then perceived construction risk will be reduced.

4.11. The regulatory regime impacts the materiality of the risk arising from exposure to capex complexity. As discussed, the presence of an ex-post cost assessment[39] in both regimes substantially reduces this risk.

4.12. For interconnectors, their capex expenditure only relates to the transmission links. For wind farm developers who also build the transmission links (offshore transitional round projects and generator build under enduring regime), the generation assets comprise the majority of the capex. This means the impact of transmission capex risk is more acute for interconnectors than offshore, until the OFTO build approach is realised.

(iii)The impact of transmission construction spend on project returns

4.13.**Assessment:** Project returns are more sensitive to transmission construction spend for an interconnector developer than for a wind farm developer.

<u>Rationale</u>

4.14. For a given design and location, developers have no incentive to inflate project capex as this reduces project returns as revenues will be the same regardless. Both interconnectors and wind farm developers have no disincentive to minimise project capex.

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[38] In the offshore regime, IDC stops when each transmission system first became available or ought to have become available to transmit. This is to avoid remunerating any inefficiency on this aspect by the developer.
[39] In the offshore regime this may encompass both a forensic accounting and technical assessments.

4.15. Similarly, both wind farm developers and interconnectors have a strong incentive to ensure the link is operational at the earliest possible opportunity. Wind farm developers are seeking to secure renewable obligation certificates (ROCs) whilst congestion revenue for interconnectors is likely to be higher whilst there is less interconnection in GB.

4.16. In this regard, the two regimes appear equivalent. However, for the wind farm developer, the majority of the capex is for the generation assets. The transmission links are the enabling infrastructure needed to transmit the power and so must be ready at or before the generation assets for the developer to earn any revenue. For an interconnector, the transmission assets are the sole business.

4.17.A wind farm developer's CoC will be higher for the generation assets, where they face full exposure to capex spend, compared to the transmission assets where all economic and efficient spend is passed through, de-risking the project. Whilst they face an incentive to minimise project capex, there is an incentive to inflate the transmission-generation split. This is the reason for technical and forensic accounting assessments in the offshore regime.

(iv)The security provided to lenders and the availability of capital

4.18. **Assessment:** A wind farm developer is able to recover the capital costs incurred on the transmission links after the assets are constructed. An interconnector developer is reimbursed, through the cap and floor, throughout the operational phase. The earlier repayment for the wind farm developer allows them to reinvest the capital in other projects and also reduces the risk for lenders.

Rationale

1.7. For the wind farm developer, the value of the economic and efficiently incurred capex on the transmission links (final transfer value) is repaid in full at financial close, ie handover of the assets to the OFTO and the commencement of the 20 year regime. Although their TNUoS charge liability is tied to this final transfer value, the wind farm developer will have been reimbursed the expenditure, making the funds available for higher return investment.

1.8. For an interconnector, the reimbursement of capex happens over the course of the operational regime through a higher level of the cap and floor for the 20 or 25 year regime.

1.9. Whilst this is a timing of cash flow consideration, lenders will consider the operational phase when making their decision about how much and at what terms to lend to interconnectors during, and potentially beyond, the construction phase. This is a new and untested regulatory regime, whereas generation has a long history.

Overall assessment

1.10. Based on our qualitative assessment of the relative level of risks faced by developers in constructing transmission assets in the two regimes, the required return by an efficient interconnector developer may need to be higher. The higher level of risk may result in a higher cost of debt and/or lower gearing level for a notionally financed interconnector developer. We welcome views on our assessment.

Appendix 5 – Tax and transaction cost allowances

5.1. Appendix 5 outlines our proposed approach on two other costs which were not covered in detail in Chapter 3, tax and transaction costs. The methodology for setting the regulatory return component of the level of the cap and floor, focused on calculating the cost of equity and debt respectively.The two other finance costs that are taken account of in onshore transmission price controls when reaching regulatory settlements are

(i) Transaction costs

(ii) Tax allowance

(i)Transaction costs

5.2. Transaction costs relate to both debt and equity. Both need to be computed to set the size of the allowance.

Debt transaction costs

5.3. The 'all-in' cost of debt for the developer is the interest payments on the debt issued and the transaction costs associated with issuing this debt. Our floor returns methodology is based on a notional efficient finance developer raising debt in line with the cost of debt index tracked.

5.4. For floor revenue, developers will receive the value of the index tracked at financial close on the whole asset base rather than just on the notionally geared proportion resulting in a low but positive RoRE. In order to cover transaction costs incurred by a notionally efficient developer a separate transaction cost allowance is appropriate, if one was not provided the developer may not be financeable.

5.5. Issuance costs are typically a proportion of the amount of debt issued. Our proposed 2.5% allowance for transaction costs is based on a National Audit Office (NAO) report and reflects how commitment and arrangement fees have changed recently.[40] The 2.5% allowance covers all fees including any swap fees. Since the notional gearing assumed during the operational phase was 50%, the 2.5% allowance, is only paid on 50% of the opening RAV.

Equity transaction costs

[40] National Audit Office (2010): Financing PFI projects in the credit crisis and the Treasury's response.

5.6. These projects are one-off investments and so an allowance for equity transaction costs is appropriate. The proposed 5% allowance, set by Ofgem in a previous price control[41] and reconfirmed by CEPA's analysis for the RIIO price controls, is higher than on the debt side. This reflects the larger indirect costs associated with issuing equity than debt, discussed in CEPA's report.

5.7. We anticipate the notional gearing for the construction phase will be lower than the operation phase. This means some of the equity issued during the construction phase either needs to be in the form of a short-term shareholder loan from the parent company or redeemed. For this reason, the 5% allowance is paid on the assumed equity proportion in the construction phase rather than the whole RAV as CEPA propose.

How the allowance is provided

5.8. Having determined the amount of the allowance, this needs to be incorporated through a higher cap and floor. CEPA's report outlines the three ways of providing this allowance: uplift to the cap and floor return; as opex; increasing the RAV. All three should produce the same net present value for the developer. Our rationale for increasing the RAV is simplicity. Treating these costs as a cost of funds does not distort the cost of capital calculations, important since this is a new regime.

(ii)Tax allowance

5.9. Developers have to pay corporation tax on any profits made. However, certain expenses are deductible against tax. In particular, interest repayments and capex allowances reduce a developer's tax liability.

5.10. A point-to-point interconnector straddles two countries. As is the case with NEMO, it is typical for both countries to have different corporate tax rates and capex allowances amongst other things.

5.11. A separate tax allowance computation is done in onshore price controls, when only one jurisdiction is involved. The tax burden can be minimised to a greater extent when two jurisdictions are involved. The computation will ensure consumers are underwriting a lower floor than if things were set on a pre-tax basis.[42]

5.12. We are proposing to perform a separate tax allowance computation, one at the floor and another at the cap. This reflects the different levels of profits associated with revenue being at the cap and floor respectively. Since we are providing a separate tax allowance, we are setting the cap and floor returns on a vanilla basis

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[41] In Transmission Price Control Review 4 (TPCR4) which ran from 2007-12.
[42] For OFTOs, IDC is set on a pre-tax basis as it results in developers receiving more in the transfer value than their outlay on capex, this gap is taxable (usually under capital gains tax).

Appendix 6 - Glossary

A

AC

Alternating current

Annuity

An annual flat payment whose Net Present Value is equal to the original cost/revenue stream.

Article 16(6)

A provision under European Commission (EC) regulation No. 714/2009. It governs usage of revenues from interconnection.

Authority

The Gas and Electricity Markets Authority.

B

Beta

A measure of the sensitivity of a company's returns to changes in the market as a whole. Two measures of beta exist. The asset beta captures the underlying business risk while the equity beta also captures the impact of the financial structure (ie gearing) of the company. The market as a whole has an equity beta of one by definition.

Bond

A type of debt instrument used by companies and governments to finance their activities. Issuers of bonds usually pay regular cash flow payments (coupons) to bond holders at a pre-specified interest rate and for a fixed period of time.

BritNed

1000MW electricity interconnector between Great Britain and Netherlands, operational since April 2011.

Breakeven inflation

The difference between the percentage yield on nominal gilts and the percentage yield on index-linked gilts of a similar maturity. Breakeven inflation, therefore, represents the level of inflation expected by investors that is priced into nominal gilt yields.

C

Capital asset pricing model (CAPM).

A theoretical model that describes the relationship between risk and required return of financial securities. The basic idea behind the CAPM is that investors require a return for the ’riskless’ element of their investment, and a return for the level of risk.

Capital expenditure (capex)

Expenditure on investment in long-lived network assets, such as gas pipelines or electricity overhead lines.

CEPA

Cambridge Economic Policy Associates Ltd.

Corporate finance

Traditional approach to funding a business where the funds are backed by the whole company rather than any specific assets

Cost of capital

The minimum acceptable rate of return on capital investment. It includes both the cost of debt to a firm, and the cost of equity.

Cost of debt

The effective interest rate that a company pays on its current debt. Ofgem calculates the cost of debt on a pre-tax basis.

Cost of equity

The rate of return on investment that is required by a company's shareholders. The return consists both of dividend and capital gains. Ofgem calculates the cost of equity on a post-tax basis.

Credit rating

An evaluation of a potential borrower's ability to repay debt. Credit ratings are calculated from financial history and current assets and liabilities. There are three major credit rating agencies (Standard & Poor’s, Fitch and Moody’s) who use broadly similar credit rating scales, with D being the lowest rating (highest risk) and AAA being the highest rating (negligible risk). The companies regulated by Ofgem typically have a credit rating of BBB, BBB+, A- or A.

CREG

Commission de Regulation de l’Electricite et du Gaz, Belgian Energy Regulator.

Crown Estate

A property portfolio owned by the Crown. The Crown owns the UK seabed out to the 12nm limit and the Crown Estates has the right to lease areas of the UK seabed for renewable energy projects.

D

DC

Direct current, unidirectional flow of electric charge

Department of Energy and Climate Change (DECC)

DECC takes the lead in energy policy and tackling climate change. This reflects the fact that climate change and energy policies are inextricably linked since two third of our emissions come from the energy we use.

Depreciation

Depreciation is a measure of the consumption, use or wearing out of an asset over the period of its economic life.

Dimson, Marsh and Staunton (DMS)

Proposed source for the standard, annually updated, measure of the equity risk premium for the UK and other countries.

E

EC

European Commission

Elia

Belgian Transmission System Operator

Energy Infrastructure Package (EIP)

This was proposed by the European Commission in 2011 with the aim of promoting the completion of Europe's 'transport core network', the 'energy priority corridors' and the 'digital infrastructure.'

Equity beta

The equity beta measures the covariance of the returns on a stock with the market return. The weaker this co-variance, the greater the contribution that the stock could make to reducing the exposure to systematic risk, and hence the lower the return that investors would require on that stock.

Equity risk premium

A measure of the expected return, on top of the risk-free rate, that an investor would expect for a portfolio of risk-bearing assets. This captures the non-diversifiable risk that is inherent to the market. Sometimes also referred to as the 'market risk premium'.

EU

European Union

Explicit allocation/auctions

Allocation/auction in which transmission capacity is allocated separately from the trading of electricity.

F

Financeability

Financial models are used to determine whether the regulated energy network is capable of financing the necessary activities of its network business and earning a return on its regulated asset value (RAV) under the proposed price control. This financeability is assessed using a range of different financial ratios.

Financial structure

The way in which a company finances its assets, for example through short-term borrowings, long-term debt and shareholder equity. This includes financial relationships within its corporate structure.

G

GB

Great Britain

Gearing

A ratio measuring the extent to which a company is financed through borrowing. Ofgem calculates gearing as the percentage of net debt relative to the Regulatory Asset Value (RAV).

Generator build option

Under this option in the GB offshore transmission regime, the generator will take responsibility for all aspects of preliminary work, procurement and construction of the transmission assets. A prospective offshore transmission owner (OFTO) will bid their approach to the financing, operation, maintenance and decommissioning of the transmission assets, and a Tender Revenue Stream value that includes the costs associated with carrying out these activities.

Gilts

The name given to bonds issued by the British government. Most gilts do not compensate the bond holder for actual changes in inflation, and are referred to as 'nominal' or 'conventional' gilts. Gilts that compensate their holder for actual movements in inflation, as measured by the Retail Price Index (RPI), are referred to as 'index-linked' gilts (ILGs).

H

HVAC

High Voltage Alternating Current.

HVDC

High Voltage Direct Current.

I

iBoxx

A data service for bonds traded in financial markets. iBoxx provides detailed information on each bond, including its price, coupon, current yield, remaining maturity and credit rating. iBoxx is published by Markit.

IFA

Interconnector France-Angleterre, 2000MW electricity interconnector between France and UK.

Implicit allocation

Allocation in which both transmission capacity and electric energy are allocated together, typically used at the day-ahead stage and potentially intra-day.

Indexation

The adjustment of an economic variable so that the variable rises or falls in accordance with a specified inflation index.

Index linked

Debt for which repayments are adjusted on the basis of some reference index (often an index of inflation).

Inflation index

A measure of the changes in given price levels over time. A common example in the UK is the Retail Prices Index (RPI), which measures the aggregate change in consumer prices over time.

Integrated Transmission Planning and Regulation Project (ITPR)

A project launched by Ofgem in March 2012, considering how Great Britain's network planning and delivery arrangements will facilitate a future integrated system for onshore and offshore transmission and interconnection.

Interconnector

Equipment used to link electricity systems, in particular between two Member States.

Interest during construction (IDC)

The financing cost allowed by the national regulatory authorities (NRAs) during the construction phase.

M

Market coupling

Method of organising implicit auctions, where a single power exchange operates across the connected areas and manages the capacity between them.

MW

Mega Watt

N

National Audit Office

The body responsible for scrutinising public spending on behalf of Parliament.

National Electricity Transmission System Operator (NETSO)

The entity responsible for operating the GB electricity transmission system and for entering into contracts with those who want to connect to and/or use the electricity transmission system.

National Grid Electricity Transmission (NGET)

NGET owns and maintains the onshore high-voltage electricity transmission system in England and Wales. It also acts as the National Electricity Transmission System Operator for GB.

National Grid Interconnector Limited (NGIL)

A wholly owned subsidiary of National Grid plc and holder of an interconnector licence. NGIL jointly own and operate the IFA interconnector (with the French Transmission System Operator, RTE) and the BritNed interconnector (with the Dutch Transmission System Operator, TenneT).

NEMO

Proposed 1000MW interconnector between Belgium and Great Britain.

Net present value (NPV)

The discounted sum of future cash flows, whether positive or negative, minus any initial investment.

Nominal return

A rate of return that includes inflation.

NRA

National Regulatory Authority.

O

Ofgem

Office of Gas and Electricity Markets.

OFTO

Offshore Transmission Owner.

OFTO build option

Under this option in the GB offshore transmission regime, the generator would obtain the connection offer and undertake high level design and preliminary works. A prospective OFTO would bid their approach to the procurement, financing, construction, operation, maintenance and decommissioning of transmission assets, and the costs associated with carrying out these activities.

OFTO licence

The licence awarded following a tender exercise, allowing an OFTO to own and operate the offshore transmission assets. The licence sets out an OFTO's rights and obligations as the offshore transmission asset owner.

O&M

Operations and maintenance.

Operating expenditure (Opex)

Expenditure on the day to day operation of a network such as staff costs, repairs and maintenance and business overheads.

P

Post-tax return

A rate of return which is received by investors and which excludes corporate taxes paid out of pre-tax returns.

Pre-tax return

A rate of return which includes the cost of corporate income tax, ie the post-tax rate of return plus the required tax.

Project finance

An alternative form of finance to corporate or traditional finance. Under project finance any funds are linked specifically to that project and investors have no recourse to the parent company if the project is delayed or fails.

Price control

The control developed by the regulator to set targets and allowed revenues for onshore network companies. The characteristics and mechanisms of this price control are developed by the regulator in the price control review period depending on network company performance over the last control period and predicted expenditure in the next

Private Finance Initiative (PFI)

A long term contractual arrangement that makes the private sector responsible for, and bear the risks of, areas including designing, building, financing, maintaining and operating a public sector facility to output specifications set by the public sector.

R

Real return

A rate of return that excludes inflation.

Regulatory Asset Value (RAV)

The value of the assets that is used by the regulator when setting an allowed level of revenue.

RES

Renewable Energy Sources.

Retail Price Index (RPI)

Measures the aggregate change in consumer prices in GB over time and is therefore a measure of inflation. It differs from the Consumer Prices Index (CPI) in that it measures changes in housing costs and mortgage interest repayments, whereas the CPI does not, they are calculated using different formulae and have a number of other more subtle differences.

Return on Equity (RoE)

The amount of net income returned as a percentage of shareholders' equity. Return on equity measures a corporation's profitability by revealing how much profit a company generates with the money shareholders have invested.

Return on Regulated Equity (RoRE)

The financial return achieved by shareholders in a licensee during a price control period from its out-turn performance under the price control. The return is measured using income and cost definitions contained in the price control regime (as opposed to accounting conventions) and is expressed as a percentage of (share) equity in the business. Importantly, in the calculation the gearing (proportions of share equity and debt financing in the RAV) and cost of debt figures used are those given as the 'assumed' levels in the relevant price control final proposals. The aim of the RoRE measure is to provide an indication of the return achieved by the owners of a licensee which can be compared to the cost of equity originally allowed in the price control settlement and to the return achieved by other licensees on an equivalent basis.

RIIO (Revenue = Incentives + Innovation + Outputs)

The RIIO price control model builds on the success of the previous RPI-X price control regime, but better meets the investment and innovation challenge by placing much more emphasis on incentives to drive the innovation needed to deliver a sustainable onshore energy network at value for money to existing and future consumers.

RIIO-T1

The first onshore electricity transmission price control under the RIIO framework, which will apply from 1 April 2013 to 31 March 2021

Risk-free rate

The cost of borrowing for a government. This is perceived as the least risky type of investment in an economy and, as such, forms the base against which all other risky investments are priced.

S

SKM

Sinclair Knight Merz..

Swap

A contract between two parties. In the case of an inflation swap, one party agrees to pay a regular (typically every six months) amount that is linked to an inflation index, eg RPI, whilst the other pays an amount that is independent of this inflation index, and is instead written into the contract when it is entered into. Swap payments are settled on a net basis so that there is only a payment from one party to the other. Which party is on balance receiving money for a period depends on the value of the inflation index in that period. Hence an inflation swap can be used to counteract inflation-linked movements in a sequence of regular cash flows.

System Operator – Transmission Owner Code (STC)

The STC defines the high-level relationship between the National Electricity Transmission System Operator and a Transmission Owner.

T

Tax allowance

A provision in the amount of revenue allowed by a regulator to enable the regulated entity to meet its tax obligations.

Third party developers

Potential interconnector operators that are not existing operators of an onshore transmission network.

TNUoS charges

Transmission Network Use of System charges.

Transaction costs

Costs associated with the issuance of debt or equity. Can be both direct and indirect costs.

Transmission Owner (TO)

An owner of a high-voltage transmission network or asset.

Transfer value

The value of an asset at the point when it moves from one phase of the regulatory regime to another (for example, from the construction phase to the operational phase, if these are treated differently).

TSO

Transmission System Operator, entity in charge of operating transmission facilities either for electricity or gas.

W

Weighted average cost of capital (WACC)

The measure of the cost of funds for a company, based on a weighted average of the cost of equity and the cost of debt.

Appendix 7 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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