UK Power Networks

Business plan (2015 to 2023)

Annex 17: Financeability of the Business Plan

March 2014

“A reliable… an innovative… and the lowest price electricity distribution group.”

UK Power Networks
Delivering your electricity

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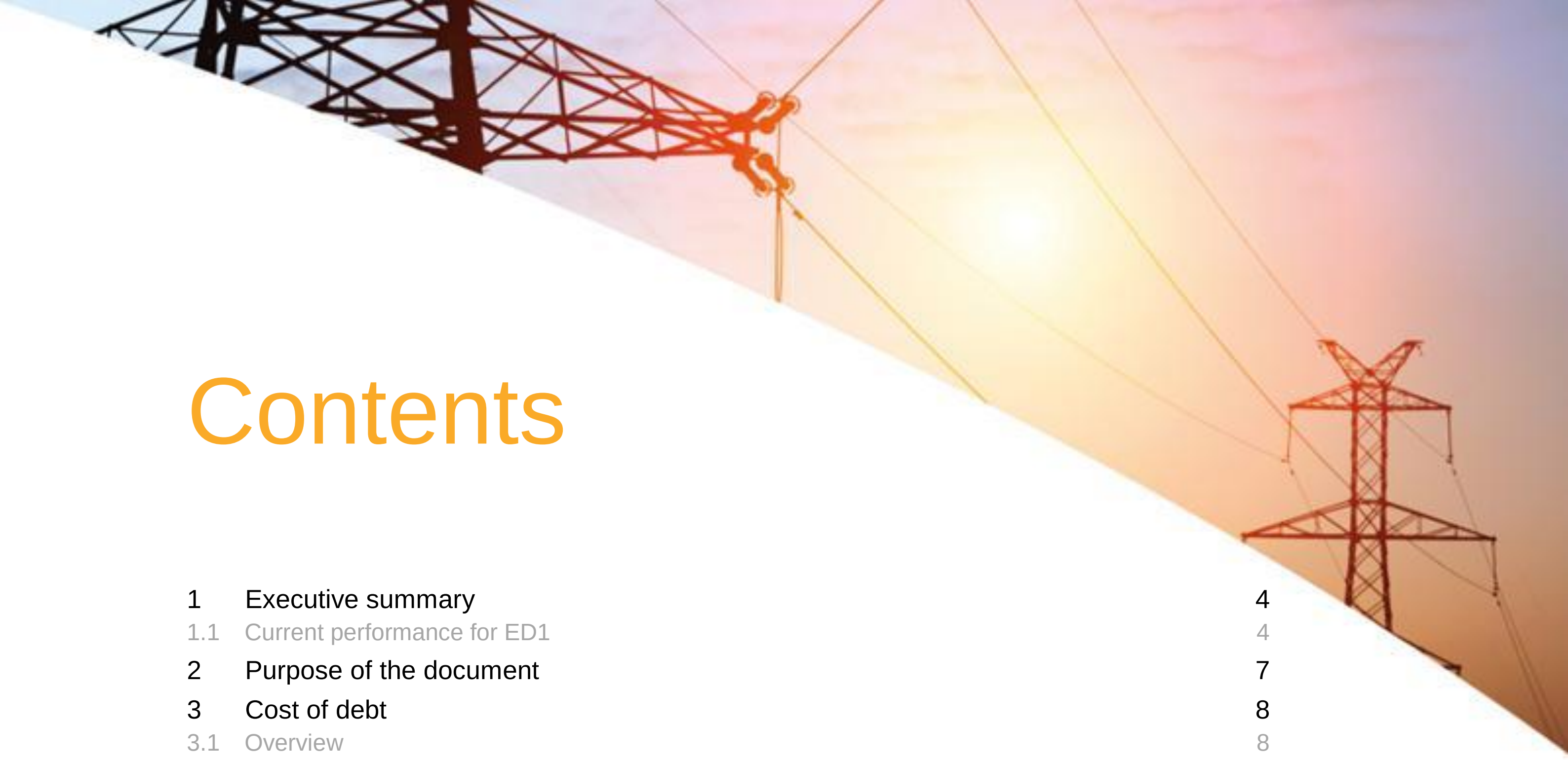
Document History

Version	Date	Revision Class	Originator	Section Update	Details
1.0	03/02/2014	N/A		N/A	Initial version (ED1 July 2013 submission baseline)
2.0	07/03/14				Update to RIIO Business Plan
3.0	13/03/2014			3.2 Forecast performance	Minor amendments to wording



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1 Executive summary

1.1 Current performance for ED1

We are required to operate our business in a financially sound manner, maintaining an investment grade credit rating and avoiding financial distress. The revenue we require to fund our business covers the costs of operation, the cost of financing our investments, the associated tax and other liabilities such as the pensions for our employees.

We are submitting a business plan that includes a financial package which we believe complies with Ofgem's financial policies, ensures confidence for our debt and equity investors and is fair on customers both today and in the future.

The overarching criteria by which we have assessed financeability are:

- Achieve credit metrics which are in line with a BBB+ rating
- Proposals that are compliant with Ofgem policies and where practicable have minimal transitional arrangements
- Provides appropriate return to investors through a combination of allowed return on equity and a plausible range of outperformance on incentive and efficiency opportunities
- Meets investor expectations over the long term, given uncertainty over long-term usage of the electricity distribution network

We have amended our proposed cost of equity to 6.0% from 6.7%. This aligns with Ofgem's revised central estimate. We do not agree with the estimate of 6.0% but we believe we will be penalised through the IQI mechanism if we do not accept it. Our acceptance is conditional on Ofgem accepting our overall business plan package, including our proposed totex and financeability proposals, and therefore on the outcome of our discussions with Ofgem and the Draft Determinations.

Since our business plan submission there has been considerable debate on the methodology for estimating to cost of equity. Historically, the key components of the cost of equity had been derived by regulators using long run historic averages. However, in its draft determination for Northern Ireland Electricity (NIE) the Competition Commission (CC) placed more weight on short run data. The consequence of using this approach is a lower estimate of the cost of equity. However, both the Competition Commission, and more recently OFWAT, considered all of the components of the Cost of Capital when coming to their draft positions on the appropriate cost of capital. Both regulators adopted an ex-ante approach to the cost of debt, compared to the use of a long run trailing average, as set out by Ofgem in its RIIO strategy document. We acknowledge that Ofgem have accepted the recommendation of Wright and Smithers to continue to use long run data to calculate the total equity market return. However, it is not clear how Ofgem have derived their 6.0% cost of equity.

We have maintained the use of the 10 year trailing average for calculating the cost of debt in line with the decision in Ofgem's March 2013 strategy document. However, it should be noted that our actual cost of debt will exceed our forecast of the cost of debt allowance by 0.55%, on average, over the ED1 period.

The table below sets out the baseline cost of capital assumed in our business plan and compares it to recent regulatory decisions.

Table 1 Cost of Capital

	UK Power Networks RIIO-ED1 March 2014 revised plan	Ofgem central estimate	OFWAT estimate	Competition Commission draft estimate for NIE	RIIO-GD1	RIIO T1 - NGET
Cost of Debt (pre-tax real)	2.6 – 1.7%	2.72%[1]	1.25%	3.4%	2.92 (2013/14 value)	2.92 (2013/14 value)
Cost of Equity (post tax real)	6.0%	6.0%	5.96%	4.8%	6.7%	7.0%
Notional gearing	65%	65%	62.5%	50%	65%	60%
Implied vanilla WACC	3.79%–3.21% (average 3.51%)	3.87%	3.70%	4.10%	4.20%	4.55%

The average assumed vanilla WACC in our plan is 3.51%. This is a cut of 1.19% (or a 25% reduction) from DPCR5 and is significantly below the most recent regulatory decisions. A key reason for this is that our cost of debt assumption reflects the latest forecast of how the iBoxx index is likely to move over the RIIO-ED1 period. Based on the latest analysis the index is expected to fall from 2.6% at the start of the period to 1.7% by the end. As a consequence we are forecasting to underperform the debt allowance by 0.55% over the ED1 period

In order to maintain financeability, given Ofgem's policy to move to longer asset lives in the RAV, we have undertaken modelling to derive the most appropriate mix of transitional measures which allow each of the networks to meet the criteria shown above. We have looked closely at each network and sought to apply a tailored approach which best serves the stakeholders in each case. Our proposed approach is as follows:

- Transition to 45 year regulatory asset lives over the ED1 period for all three networks
- Adopt a 32%:68% between fast and slow money for all three networks. This is a 2% increase in fast money but remains within the range described by our historic statutory and our regulatory fast and slow split. This change to our business plan is required to ensure our financeability in the RIIO-ED1 period given Ofgem's lower allowed WACC.
- Adopt the following revenue profiling assumptions for each network to ensure all three networks broadly satisfy the rating agency credit metrics over the ED1 period

Table 2 Summary of Po and X

	EPN	LPN	SPN
Po	– 5%	– 12%	– 13%
Annual X[2]	2.0%	1.8%	2.7%

[1] This is the current modelling assumption contained within Ofgem's RIIO-ED1 price control model. This figure will change throughout ED1 to reflect movements in the 10 year trailing average of the iBoxx index.

[2] These Pos reflect the Ofgem cost of debt modelling assumption. We expect the actual allowed cost of debt to fall in ED1 in line with the movement in the relevant iBoxx 10 year average. Consequently, we expect the actual year on year increases to be smaller.

- Maintain notional gearing of 65% across our three networks
- Our business plan assumes roll forward of the pension deficit at 31/12/2012 and it will continue to be recovered over the remaining years of the current recovery plan ending in 2025
- Our business plan is consistent with the RIIO-ED1 principles and Ofgem proposed policies for taxation

2 Purpose of the document

This annex sets outs UK Power Networks' assessment of its financeability requirements to operate our business in a financially sound manner, maintaining an investment grade credit rating and avoiding financial distress. It also confirms UK Power Networks' compliance with Ofgem Finance Policies.

The annex incorporates a review of the cost of debt and cost of equity together with the resultant weighted average cost of capital (WACC). It also includes the results of modelling of the financeability of UK Power Networks' three networks.

3 Cost of debt

3.1 Overview

In the March 2013 Strategy document it was stated that the cost of debt allowance in the WACC for RIIO-ED1 would be based on a 10-year simple trailing average index to be updated annually during the price control. It is proposed that the cost of debt allowance will be calculated as an average of the iBoxx GBP Non-Financials Indices of 10+ years maturity, with credit ratings of broad ‘A’ and broad ‘BBB’ issuers, deflated by 10-year breakeven inflation data published by the Bank of England.

Table 3 details our forecast for the value of this trailing average index for each year of RIIO-ED1. We have updated this forecast to reflect the latest information. The forecast cost of debt index has reduced quite markedly since early last year even though spot term interest rates have actually risen. This is because the change in the shape of the yield curve means that forward starting interest rates have actually fallen (the curve becomes inverted in later years) which acts to depress the index. In addition, credit spreads have also compressed which reduces the index further. This profile has been used throughout our financial analysis.

Table 3 RIIO-ED1 iBoxx cost of debt forecast

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Cost of Debt (iBoxx)	2.6%	2.5%	2.4%	2.3%	2.1%	1.9%	1.8%	1.7%

These forecasts have been calculated using a methodology described below.

Historic data has been derived from a combination of Ofgem’s indexation model, the Bank of England’s website and Bloomberg. Forward swap rates have been derived from internal models maintained by one of our key UK relationship banks and are based on observable market swap rates.

- The average maturity of the two indices is:
  – iBoxx ‘BBB’ index – currently approximately 18 years
  – iBoxx ‘A’ index – currently approximately 23 years
- For modelling purposes, forecast future underlying interest rates are based on a single maturity swap, (namely 20 years). Swap market rates are used to imply forward 20-year swap rates at the beginning and end of each calendar year. The average for the year is taken as a simple average of the two valuations
- A credit spread is added to the average swap rate to derive a forecast average iBoxx index yield for each calendar year. In 2013 the average of the iBoxx ‘A’ index was 1.35% above the 20-year swap rate. In 2013 the average of the iBoxx ‘BBB’ index was 1.71% above the 20-year swap rate. This implies an average credit spread over swaps of 1.53%
- Using the Fisher Equation, the nominal forecast average iBoxx yield is deflated by the forecast breakeven inflation for the corresponding year to derive a projected real index value for the year. The differential between historic 10-year breakevens (difference between 10-year nominal gilts and 10-year real gilts) and 10-year zero coupon inflation swaps averaged 0.27% over the period January 2005 to December 2013. Projected breakevens are therefore derived by implying forward inflation swap rates from swap markets and adjusting downwards for the assumed 0.27% differential. A simple average of opening and closing rates for each year is used as the deflating rate

This approach gives a projected real cost of debt value for each year of RIIO-ED1 as shown in Table 3. A 10-year trailing average of actual and projected rates is then calculated to derive a real cost of debt index for each year.

The key assumptions underpinning this modelling are detailed below:

- Future credit spreads are assumed to remain in line with observed spreads in 2013;
- The future differential between 10-year gilt breakevens and 10-year zero coupon inflation swaps is assumed to be consistent with observed data from 2005 to 2013;
- The average maturity of bonds across the two relevant iBoxx indices is assumed to remain close to 20 years. The move to a 10-year trailing average index in reality is likely to push debt issuance by network operators towards shorter tenors and change the composition of the both indices over time (currently circa 52% utility bonds); and
- Average future swap rates (both 20-year nominal and 10-year inflation) are based on a simple average of opening and closing rates in each calendar year. Forecasting daily, weekly or monthly rates was considered too onerous for this exercise.

3.2 Forecast performance

Forecast UK Power Networks' performance versus forecast cost of debt index

The table below shows UK Power Networks' forecast cost of debt performance versus the forecast cost of debt index derived as described above.

Table 4 Forecast cost of debt performance versus index

	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	ED1 average
Cost of Debt (iBoxx)	2.6%	2.5%	2.4%	2.3%	2.1%	1.9%	1.8%	1.7%	2.16%
UK Power Networks' Cost of Debt	2.6%	2.6%	2.6%	2.7%	2.7%	2.9%	2.8%	2.8%	2.71%

As can be seen from Table 4 we are forecasting to meet the cost of debt allowance in the first year of the price control and then move to a position of underperformance for the rest of the price control.

We have taken a close look at our future debt issuance and derivatives strategy and tailored this to reduce cost of debt as far as possible for the RIIO-ED1 price control and beyond. The benefits of this strategy have been overlaid in the forecasts above and include actions such as:

- Raising new debt with shorter tenor and in smaller amounts to allow more frequent visits to debt capital markets
- Avoiding very large maturities in any one particular year
- Using derivatives to maintain up to one third of the debt portfolio in index-linked form, with the remaining balance split between fixed rate and variable rate

Having modelled these actions in the forecasts in Table 4, we are forecasting to be in a position of underperformance in the second half of RIIO-ED1. The main driver for this is that UK Power Networks will enter the start of the price control with a significant amount of fixed debt and embedded derivatives which are in existence today and cannot be restructured without incurring significant cost.

We believe this underperformance coupled with Ofgem's position on the cost of equity raises financeability issues for our licensees in ED1.

4 Establishing the cost of equity

Theoretical considerations

The application of the standard CAPM approach to determining the cost of capital, and in particular the cost of equity is difficult in the current market conditions. As Oxera highlight in their paper (follows Appendix A.1) a number of factors contribute to this. These include:

- The aftermath of the most serious financial crisis in recent decades, with extended periods of high market volatility
- The impact of several rounds of quantitative easing and a general loosening of monetary policy
- Continuing increased uncertainty with respect to key market fundamentals i.e. inflation and output
- Changes in the regulation and investment strategies of financial institutions e.g. the impact of pension fund investment in index linked yields

These factors have led to a divergence between the short run estimates of the risk free rate, and the equity risk premium and the long run estimates. This makes it especially challenging to forecast the cost of equity in the context of an eight year price control.

Since our business plan submission there has been considerable debate on the cost of equity. In its draft determination on NIE the CC has proposed to put more weight on forward looking estimates of the total equity market return. However, we note that Ofgem has accepted the recommendation from Wright and Smithers that there is no strong case for changing the current methodology. We agree with this approach.

The table below compares the RIIO–ED1 strategy decision range with the most recent regulatory decisions.

Table 5 Initial range for the cost of equity

	RIIO-Slow track (2014)	RIIO-ED1 Strategy (2013)	OFWAT[3] (2014)	Competition Commission on NIE[4] (2013)	RIIO-GD1 (2013)	RIIO-T1 (Gas) (2013)	RIIO-T1 (Electricity) (2013)	DPCR5 (2010)
Risk free rate (%)		1.7 – 2.0	1.25%	1.0 -1.5	2.0	2.0	2.0	2.0
ERP (%)		4.75 – 5.5	5.5%	4.0% - 5.0%	5.25	5.25	5.25	5.25

[3] Regeared to 65%

[4] Regeared to 65%. The equivalent CC cost of equity range at 65% gearing is 4.8% to 7.0%. 6.1% is the 60th percentile in the range, consistent with the CC's positioning of its point estimate.

	RIIO-Slow track (2014)	RIIO-ED1 Strategy (2013)	OFWAT[3](2014)	Competition Commission on NIE[4] (2013)	RIIO-GD1 (2013)	RIIO-T1 (Gas) (2013)	RIIO-T1 (Electricity) (2013)	DPCR5 (2010)
Equity beta		0.90–0.95	0.86	0.96 – 1.10	0.90	0.91	0.95	0.90
Cost of equity (post tax real)	6.0%	6.0%–7.2%	5.96%	6.1%	6.7%	6.8%	7.0%	6.7%

The table shows that 6.0% is in line with current regulatory positions. However, in its consultation document Ofgem stated that the 6.0% reflected an allowance for embedded debt costs. As there was no detailed calculation it is difficult to understand the quantum of this implied allowance.

Risk free rate

The table below sets out a comparison of the recent regulatory determinations on the risk free rate. It shows that with the exception of Ofcom, regulators have typically set the risk free rate higher than the observed spot rates. This is appropriate and reflects the uncertainty over the future risk free rate, caused by a number of the factors highlighted in the section above. With respect to the Ofcom decision it should be remembered that:

- Ofcom's determination applies to a three year rather than an eight year price control and hence the risk of error in the cost of capital estimate is likely to be lower
- Ofcom does not have an explicit financing duty suggesting that the risk of underinvestment may have a less significant role in setting the cost of capital

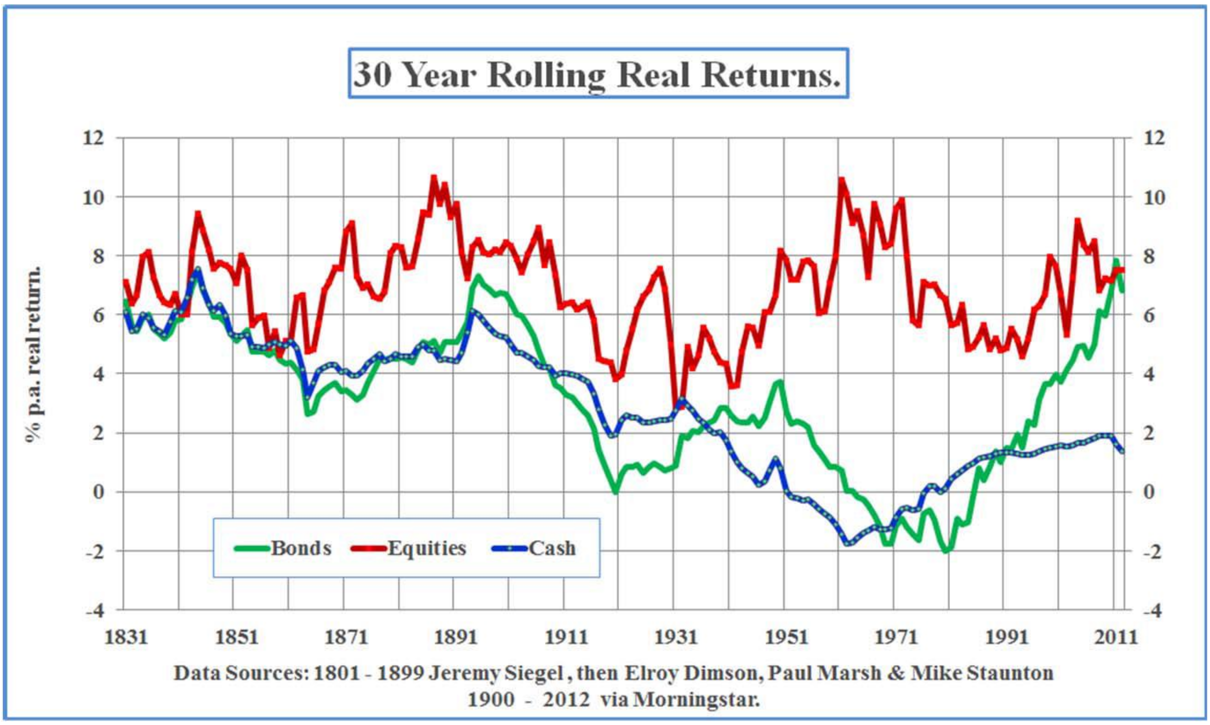
For RIIO-ED1 we believe it is appropriate to set the regulatory allowance for the risk free rate above the current spot rates.

Table 6: Real risk-free rate regulatory determinations

Regulator	Year	Risk free rate (%)
Ofgem (2001)	2001	2.8
Ofgem (2004)	2004	2.8
OFWAT (2004)	2004	2.9
Postcomm (2005)	2005	2.5
Ofcom (2005)	2005	2.1
Ofgem (2006)	2006	2.5
Ofgem (2007)	2007	2.5
ORR (2008)	2008	2.0
CC (2008)	2008	2.5
CC (2009)	2009	2.0
Ofcom (2009)	2009	2.0
OFWAT (2009)	2009	2.0
Ofgem (2009)	2009	2.0
CC (2010)	2010	2.0
CAA (2010)	2010	1.8
Ofcom (2011)	2011	1.4
Ofgem (2012)	2012	2.0
CC (mid-point estimate 2013)	2013	1.3
OFWAT (point estimate 2014)	2014	1.3

Equity Risk Premium

The Equity risk premium (ERP) is not directly observable and hence determining the appropriate value requires a degree of judgement. As part of its consultation into the cost of equity Ofgem asked Smithers and Wright to review the methodology for calculating the total equity market return. The outcome of that review was that there was no evidence to support a reduction in the total equity market return for either a reduction in the risk free rate, or other more recent market movements. Their conclusion is the total market return has remained very stable over time as illustrated by the graph[5] below on US market returns.



They have updated the original 2003 analysis and concluded that the total equity market return range should be revised from 6.5% to 7.5% to 6.25% to 7.25%. Their conclusion is that incorporating recent data into the analysis implies a revised range of 6.25% to 7.25%. The mid-point of this range is 6.75%.

A revised cost of equity

The table below details a revised cost of equity based on the recent regulatory decisions.

[5] "The Cost of Equity Capital for Regulated Companies: A review for Ofgem", Stephen Wright and Andrew Smithers, 2014. Page 4.

Table 7 Implied cost of equity calculation

Factor	Value	Rationale
Risk free rate	1.25%	OFWAT and CC draft positions
Total market return	6.75%	Midpoints of revised Wright and Smithers range
Equity Beta	0.91	Midpoint of OFWAT point estimate (relevered) and bottom of CC range
Implied cost of equity	6.26%	

There is a consensus amongst regulators that the revision to the RPI calculation methodology has resulted in a 0.4% increase in the gap between RPI and CPI. We note that Smithers and Wright suggest that 0.4% should be the maximum correction made and due to the uncertainties with respect to the calculation of the adjustment a more prudent approach would be to apply a 0.25% correction. Taking the latter into account would imply a cost of equity of 6.01%.

However, in its decision on the cost of equity Ofgem stated that its cost of equity included an uplift to recognise that the RIIO-ED1 cost of debt methodology may not allow companies to recover efficient embedded debt costs. As our cost of debt analysis shows we are likely to underperform the cost of debt index by 0.55% over RIIO-ED1. Based on a notional gearing of 65% this would imply an uplift to the cost of equity of 1%, to allow for the under-recovery. This would imply a cost of equity of 7.0% to cater for the embedded debt issue. Ofgem have not published the detail of their 6.0% so it is impossible for us to reconcile this position.

Interaction with the IQI additional income term

The headline cost of equity for DPCR5 was 6.7%. However, companies were effectively allowed a “top up” to this allowed cost of equity through the IQI additional income term. The impact of this term was to increase the baseline cost of equity from 6.7% to 7.75% (real) for a DNO which delivered its outputs and met its allowances. It could be inferred that the latter was Ofgem’s actual view on the cost of equity at that time for the average DNO. For the UK Power Networks companies specifically the impact of the additional income term was to add an additional 0.4% to the cost of equity for the DPCR5 period.

Similarly in the recent RIIO-GD1 review Ofgem set the base cost of equity at 6.7%. However, as with the previous electricity distribution review companies were effectively allowed a “top up” to this allowed cost of equity through the IQI additional income term. For the GDNs this allowed an additional 0.1% on the cost of equity, implying a required rate of 6.8%. We have therefore used this as a basis for our comparison between RIIO-ED1 and RIIO-GD1.

For RIIO-ED1 Ofgem has only published a fast track IQI matrix. It is unclear what the parameters of the slow track IQI matrix will be, however draft versions of this matrix assumed that there would be no benefit from the additional income term. Consequently, if this element of the return is no longer achievable through the IQI mechanism it should be recognised in the baseline cost of equity.

Quantifying the change in risk in RIIO–ED1

The key driver to the underlying risk within a price control is understanding the impact of the changes in the framework on the likely range of cash flow volatility. The key changes in the framework which will have an impact are:

- Scale and nature of totex
- The length of the price control
- Efficiency incentive rate
- Use of uncertainty mechanisms
- Cash flow duration
- Regulatory incentives
- Transitioning to RIIO pension principles

We have undertaken two separate pieces of work to understand the impact of these changes on the risk facing distribution network operators. Both of these methodologies focus on analysing the impact on risk from the proposed changes in the regulatory framework. Each of these is described below:

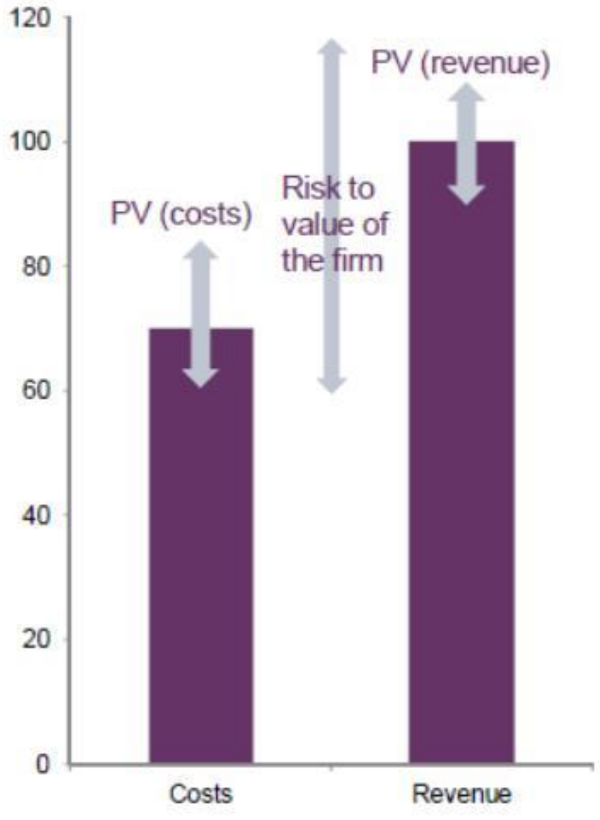
Impact of changing risk on the asset beta

The Electricity Networks Association commissioned OXERA to undertake an analysis of the impact on asset risk due to the changes in the regulatory framework. The basic premise of this work is that:

- The asset beta of an organisation is driven by the underlying risks of revenues and costs
- Both higher revenue and higher cost volatility increase the volatility of the return on assets i.e., increases asset risk
- The relative contribution of revenue volatility (risk) to the firm depends on the ratio of present value (PV) of revenue to the value of the firm
- Similarly, the relative contribution of cost volatility (risk) to asset risk depends on the ratio of PV of costs to the value of the firm

This concept is illustrated in the chart below:

Figure 1 Illustration of the relationship between revenue, costs and asset value



The analysis examined each of the factors shown in the section on quantifying the change in risk in RIIO-ED1 above and, where practicable quantified the impact on asset risk. The full detail of the analysis is contained in the Oxera RIIO-ED1 Risk Assessment Framework paper following Appendix A.1, but a summary of the overall outcomes is shown below:

Table 6 Change in asset risk in RIIO-ED1 compared with DPCR5

Risk factor	Relationship with asset risk	Change in asset risk
Scale of TOTEX	A higher ratio of costs to asset value increases potential deviation of average return on assets from forecast; total cash costs (ie, TOTEX) are what is important for determining asset risk; change in risk depends on unexpected changes in long-term expected ratio of costs to asset value	—
Nature of TOTEX	Changes in the nature of TOTEX could affect cost volatility, and, subsequently, asset risk; if forecasting TOTEX in RIIO-ED1 is more challenging (eg, due to uncertainty around the take-up of low-carbon technologies), this would increase potential deviation of costs from forecast	✓
Length of the price control	A longer price control increases potential deviation of average return on assets from forecast; timing of revenue adjustments and having fewer regulatory resets does not fully mitigate the increase in risk	5–15%
Efficiency incentive rate	A higher efficiency incentive rate increases potential deviation of average return on assets from forecast	Depends on company plans ~0.5–1% increase for every 1% proportionate increase[1]
Uncertainty mechanisms	Most mechanisms are similar to DPCR5; new mechanisms address new risks not present at DPCR5; some mechanisms are being removed	—
Cash-flow duration	Increase in regulatory asset lives increases the required rate of return	Up to ~5%[2]
Regulatory incentives	Some incentives are being removed (eg, losses incentives), while others are being introduced or strengthened. Total return exposure proposed to remain largely similar	—
Pensions	Transitioning fully to RIIO pension principles	✓✓
Total	**Asset risk is expected to go up**	**Total increase is in the range of 5–20%**[3]

Note: —, no material change; ✓, change is uncertain but likely to be positive; ✓✓, positive change but cannot be quantified. [1] The comparison should also take into account the change from a pre-tax to a post-tax application of the incentive rate. [2] The upper bound of 5% is before the effect of any transitional arrangements applied to new assets. [3] The range includes the impact of quantifiable factors only, and is before taking into account any changes in the efficiency incentive rate. The change in asset risk reflects the increase in the asset risk premium (difference between vanilla WACC and the risk-free rate) since DPCR5. Since the cost of debt in RIIO-ED1 will be indexed to a generic bond index, the increase in asset risk needs to be fully reflected in the equity beta. For more details, see Oxera (2012), 'Determining efficient financing costs for RIIO-ED1', September, Table 2.2.
Source: Oxera.

The table below highlights the impact on the equity beta, for the change in risk parameters discussed above for different notional gearing assumptions. This has then been compared to the DPCR5 equity beta range.

Table 8 Equity Beta Range

	60% notional gearing	65% notional gearing
Oxera forecast equity beta range	0.89 to 1.02	0.96 – 1.12
Ofgem DPCR5 equity beta		0.90 – 0.95

The implication from the table above is that asset risk has increased from DPCR5. However, as Oxera recognised they did not have sufficient information to model the full impact of the uncertainty mechanisms or the impact of management action. In order to provide an alternative view we have modelled the change in risk using a different methodology and focusing on the specific impact on the UK Power Networks.

Sharpe's ratio method

The second approach we have used to quantify the change in risk is to use the Sharpe's ratio. The formula for this ratio is shown below and the basic premise of the analysis is to quantify any change in equity risk premium between DPCR5 and RIIO-ED1.

Sharpes ratio = $(R_{DR5} – R_{fDR5})$/St Dev – (R_{ED1}/St Dev)

The modelling process began with a thorough design exercise to determine which factors of the RoRE calculation should be prioritised in our uncertainty modelling. At this stage we evaluated each of the factors within the calculation against two dimensions; true variability and magnitude of impact, applying a consistent and transparent methodology to measure each of the RoRE components. Each component was scored along spectrums of high, medium and low against both of these measures, with the scores underpinned by a combination of both UK Power Networks financial forecasts and consultation with UK Power Networks business experts.

True variability – Represents the extent of potential variability, and therefore uncertainty. Due to the nature of many RIIO-ED1 uncertainties, such as low carbon technologies, and the lack of relevant historic data available, the scorings for true variability took a more consultative form supported by anecdotal evidence from business experts. For areas of potentially high variability where relevant historic data is available, such as faults, this was later incorporated within the model build.

Magnitude of impact – Represents the level of impact resulting from any uncertainty in each RoRE component. For expenditure items UK Power Networks financial forecasts were used to underpin these classifications while, for incentive mechanisms, the maximum revenue cap was used. High represents > £25 million expenditure / revenue per annum across EPN, LPN and SPN, medium if > £10million expenditure / revenue per annum across the three DNOs and low if < £10million expenditure / revenue per annum.

Priority to investigate – The below table was used to translate the true variability and magnitude of impact into a level of priority for modelling. All high priority components are included in the uncertainty model.

Figure 2 Priority matrix used to determine which RoRE factors are of high, medium and low priority

True Variability

Magnitude of impact	None	Low	Medium	High
None	Low	Low	Low	Low
Low	Low	Low	Low	Medium
Medium	Low	Low	Medium	High
High	Low	Medium	High	High

A full list of the drivers and there rankings is contained in Appendix A.1.

As an example load related expenditure was assessed as a high/high under the assessment. The high ranking under the variability criteria is driven by the range of load related expenditures which could arise under differing low carbon technology scenarios. The latter are obviously outside of our control and represent a new cost driver compared to DPCR5.

Asset replacement expenditure was ranked as a high/low. Whilst the cost impact is as high as for load related expenditure we believe the costs are less variable. The biggest risk we face in this area is that our assumptions on asset degradation rates are incorrect. This is not a new risk compared to DPCR5 and since DPCR5 we have improved both our understanding and modelling of asset through tools such as Asset Risk Prioritisation. We have therefore not included this in the analysis.

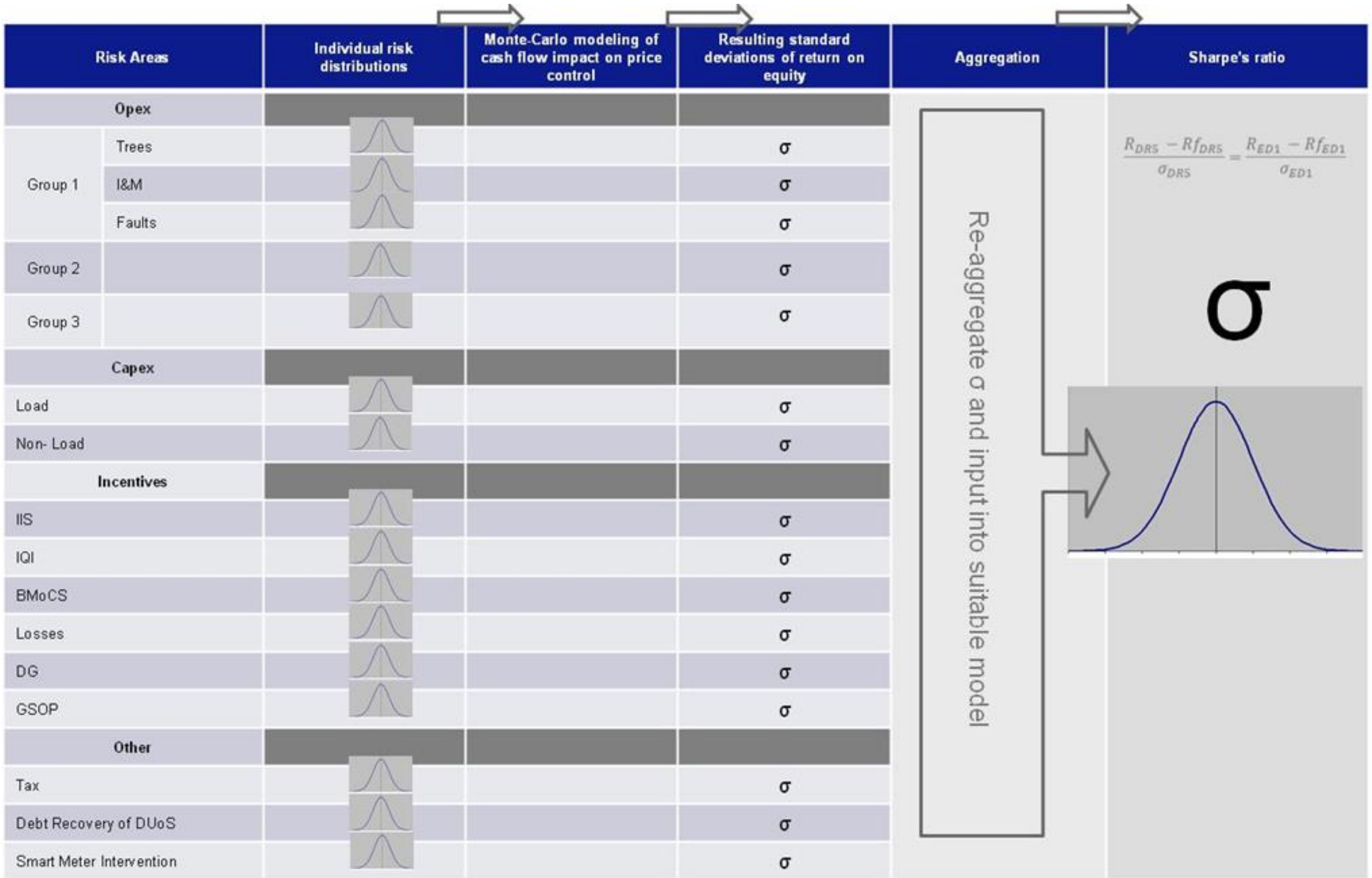
The main revenue drivers which affect cash flow volatility, and hence risk, are related to the incentive schemes. The key incentive schemes we have considered are IIS, broad measure of customer satisfaction, time to connect and network losses. The impact of the IQI incentive mechanism has been considered as part of the cost variability analysis as in effect it mitigates some of this variability.

For those drivers selected for further modelling we have:

- Assigned a probability distribution which we have derived based on the available historic data. A distribution is constructed for both the DPCR5 period and the RIIO-ED1 period
- Monte Carlo simulations are then run to produce an analysis of the standard deviations for each driver
- The output of this analysis is then used to derive the change in the cost of equity for any change in risk between the two price control periods

The process is shown diagrammatically on the next page.

Figure 3 Sharpe's Ratio Model



The initial output of the model is an evaluation of the unconstrained risk between price control periods. However, the actual risk that we will face will be affected by two factors:

- Uncertainty mechanisms
- Management action

For example, the largest risk that we face relates to the growth in network capacity due to the impact of the transition to the low carbon economy. However, this is mitigated by the use of the load related reopener which means that our overall exposure is limited to +/- 20% around the baseline. This is further reduced by the impact of the IQI sharing factor which limits the exposure to a maximum of 65%.

Management action is harder to quantify. If a cost shock occurs we expect to be able to either re-optimise our investment plan and/or deploy an alternative approach e.g. utilising an innovative solution to mitigate the impact of the cost shock. The impact of this is difficult to quantify. In our current plan we have included smart solutions that reduce our load related investment cost by approximately 10%. We have therefore assumed that a further 5% to 10% can be applied to the outcome of the risk analysis as a proxy for management action.

The graphs below show the comparison of the variation between the key risk drivers we have identified and include the impact of both the uncertainty mechanisms for each of our networks.

Figure 4 EPN analysis

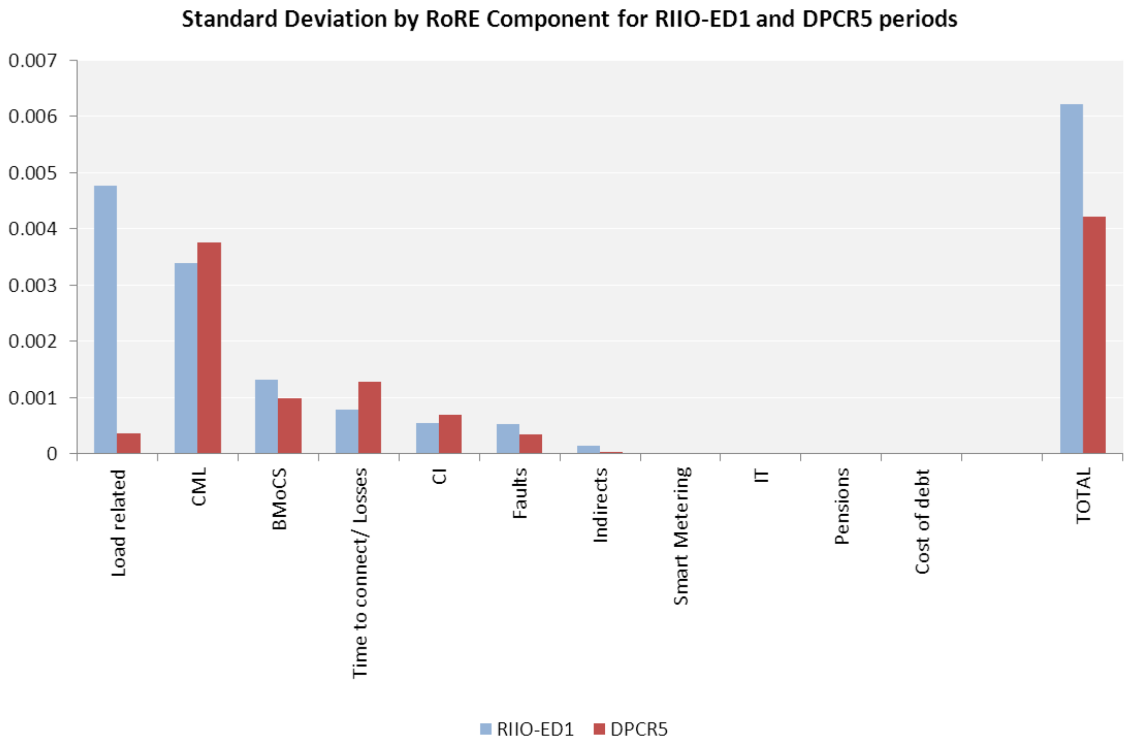


Figure 5 LPN analysis

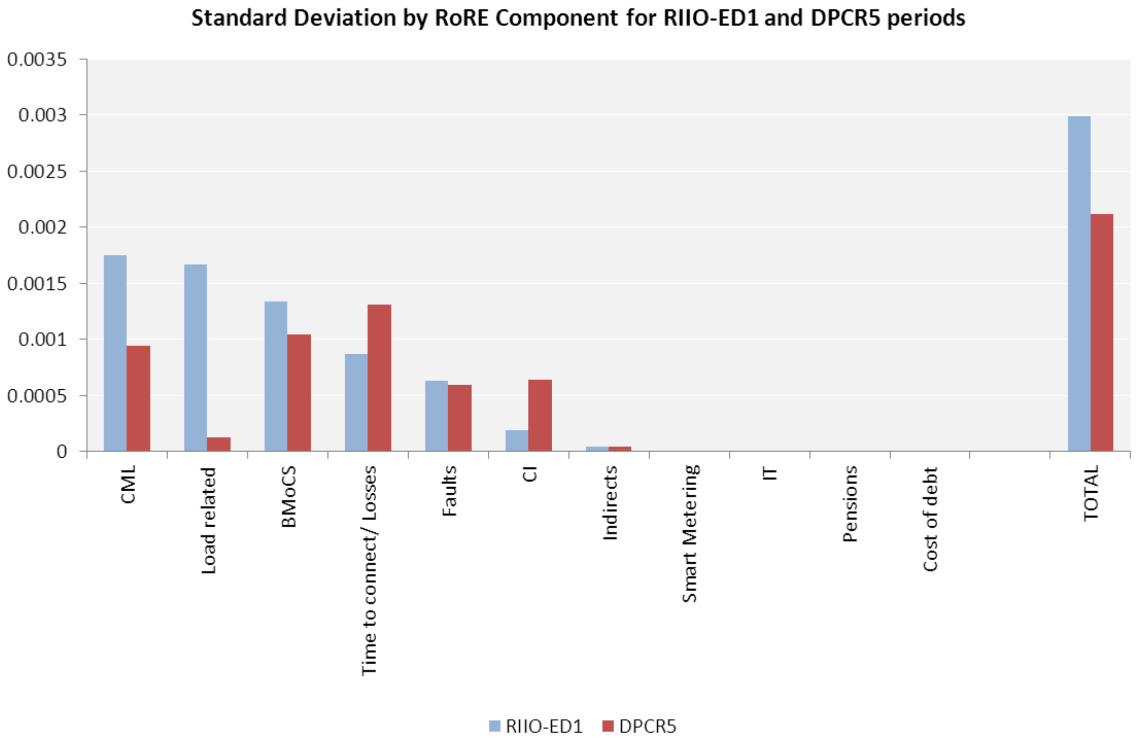
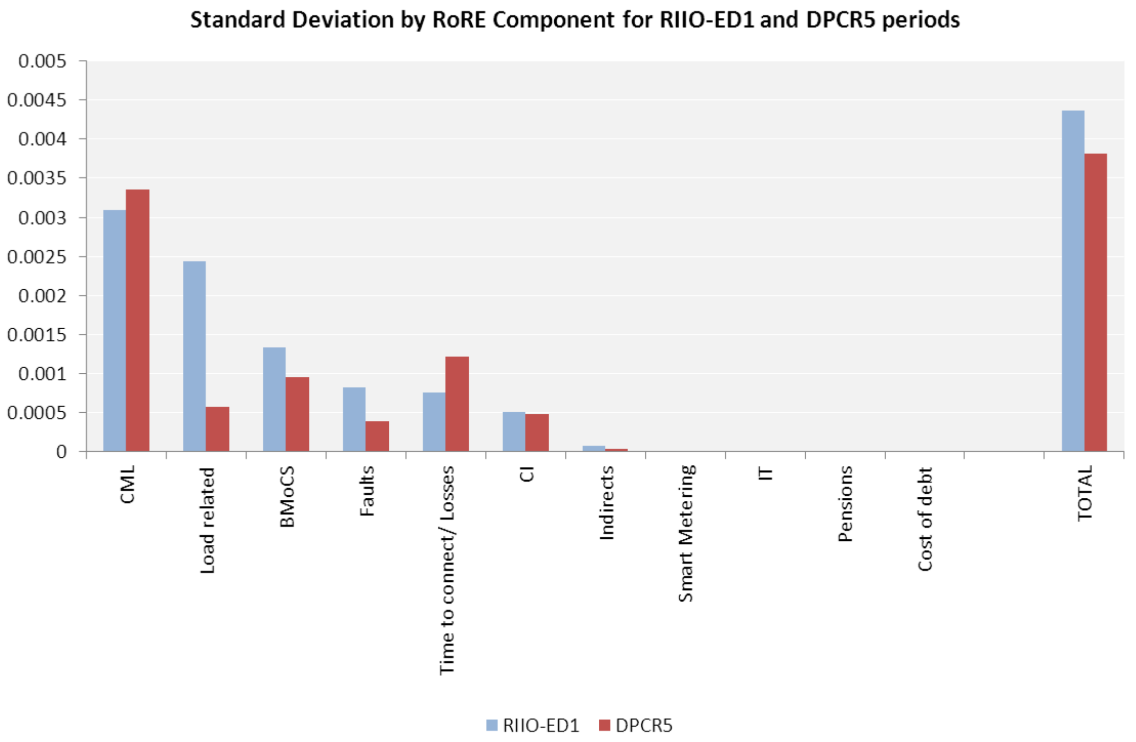


Figure 6 SPN analysis



The output of the modelling illustrates that compared to DPCR5:

- The uncertainty surrounding the impact of the transition to the low carbon economy has increased risk This element results in the largest increase in risk

- The impact of the tightening of the IIS targets has increased risk
- The removal of the losses mechanism has reduced risk

The outcome of this analysis, before management action is applied, is that the equity risk premium for RIIO-ED1 would fall within the range 5.3% to 7.1%. We have found from the methodology used that the impact of the transition to the low carbon economy has a significant impact on the outcome. For example if the yearly impact is modelled then the equity risk premium in EPN rises to 14%. This is driven by the significant ramp up in low carbon technology penetration at the end of RIIO-ED1 compared to our own assumptions which show a more even annual take up. We have therefore used both a cumulative year on year impact analysis and a price control period average to determine the range described above to produce a more realistic output.

Comparison to RIIO-GD1 and RIIO-T1

The cost of equity assumptions developed for RIIO-GD1 is the most recent regulatory analysis in this area. The following table details a high level assessment undertaken by OXERA which examined the relative risk position between the various energy networks. The outcome of this high level qualitative analysis is that on balance electricity distribution is likely to be more risky that gas distribution.

Table 9 Asset risk in RIIO-ED1 compared with RIIO-TD1 and GD1

Risk factor	Comparison with RIIO-T1	RIIO-ED1 asset risk relative to RIIO-T1	Comparison with RIIO-GD1	RIIO-ED1 asset risk relative to RIIO-GD1
Scale of TOTEX	Could be closest in the risk exposure to NGET, assuming similar nature of TOTEX	Varies by transmission operator	Could be higher risk than the GDNs, assuming similar nature of TOTEX	✓✓
Length of the price control	Could be slightly higher due to different licence disapplication conditions	✓	Could be slightly higher due to different licence disapplication conditions	✓
Efficiency incentive rate	Depends on company plans: lower end of RIIO-ED1 proposed range comparable to T1 numbers	—	Depends on company plans: upper end of ED1 proposed range comparable to GD1 numbers	—
Uncertainty mechanisms	Not directly comparable	n/a	Not directly comparable	n/a
Regulatory incentives	Cash-flow volatility could be higher	✓	Cash-flow volatility could be higher	✓
Pensions	Higher	✓✓	Higher	✓✓
Total	**Could be closest in risk exposure to NGET, assuming similar nature of TOTEX**	**Varies by transmission operator**	**Likely to be higher risk than the GDNs, assuming similar nature of TOTEX**	✓✓

Note: —, unclear at this stage; ✓, uncertain but likely to be higher risk; ✓✓, likely to be higher risk but cannot be quantified. GDN, gas distribution network.
Source: Oxera.

With respect to gas distribution an additional factor is that the transition to low carbon economy is likely to have a more material impact on the electricity network costs, both of developing and operating the respective networks.

Our view on the cost of equity for RIIO-ED1

Both sets of quantitative analysis would suggest that the cost of equity should rise. However, as we have previously stated the cost of equity is a judgement based decision and a number of qualitative factors also need to be taken into account.

With respect to analysis on the asset beta the upper end of the range looks less plausible than the lower end, as it is difficult to argue that electricity distribution is more risky than the market as a whole. Additionally, if we accept that we can influence the risks we face by between 5% – 10% then the equity beta range would fall to circa 0.9% to 1.0%.

For our own risk based analysis the key variable is the impact of the transition to the low carbon economy. The quantitative analysis implies that this is contributing to a significant increase in risk. However, again from a logical perspective the upper end of the range looks less credible than the lower end. We believe we would be able to mitigate some of this risk if the penetration of low carbon technologies was to vary from our assumptions. We have set out in our managing uncertainty annexe the tools and techniques we would use to manage this risk including the development of a low carbon penetration activity index.

However, since our business plan submission Ofgem have published a revised position that they will use a cost of equity of 6.0% to assess DNO business plans. We are concerned that Ofgem have not published the detail of how they have derived this figure, particularly with respect to how embedded debt is recognised. Our calculation of recognising this embedded debt shortfall would add 0.55% to the cost of equity. For the purposes of the business plan submission we have adopted Ofgem's proposed central estimate for the cost of equity of 6.0%. We will be seeking to discuss the final cost of equity to be used in the Draft Determinations with Ofgem during the next phase of the process.

5 Financeability

5.1 Overview

We are submitting a business plan that includes a financial package which we believe complies with Ofgem's financial policies, ensures confidence for our debt and equity investors and is fair on customers both today and in the future.

The overarching criteria by which we have assessed financeability are:

- Achieve credit metrics which are in line with a BBB+ rating
- Proposals that are compliant with Ofgem policies and where practicable have minimal transitional arrangements

Totex capitalisation

In determining the totex capitalisation percentage Ofgem will have regards to:

- The forecast business plan capitalisation rates
- Historic capitalisation rates derived from the regulatory accounts

The table below shows both the historic capitalisation percentages for each of our licence networks. The detailed calculations can be found in Appendix A4:

Table 10 Totex capitalisation

	Average five year historic statutory capitalisation (07/08 – 11/12)	Average five year historic fast and slow split (07/08 – 11/12)
EPN	75:25	68:32
LPN	74:26	64:36
SPN	77:23	68:32
UK Power Networks	76:24	67:33

We have proposed a totex capitalisation percentage of 68%. This is lower than our current statutory capitalisation but is required to ensure financeability in the ED1 period.

5.2 Assessing financeability

The base case scenario is based on the following assumptions:

- Totex capitalisation is set in line with actual statutory levels and forecast levels (Ofgem policy)
- Regulatory asset lives transition to 45 years from the start of ED1 (Ofgem policy)
- Notional gearing is set at 65% (DPCR5 outcome)
- Equity dividends are set at 5% of regulatory equity

The table below shows the impact on the credit rating agency metrics before the application of these adjustments. We have not applied profiling to this analysis as once the revenue is profiled the linkage between the calculated RAV depreciation and the revenue is broken. The reason for this is that too much depreciation is excluded from the adjusted interest cover ratio in the early years of the ED1 period and too little is excluded in the latter half of the period, hence skewing the metric. It should also be noted that Ofgem recognise their analysis does not include all of the rating adjustments particularly in relation to pension deficit. Hence, it is inappropriate to directly compare these results to the rating agency metrics. We have also updated the cost of debt allowance to reflect the iBoxx assumptions and our forecast cost of debt contained in Section 3.

Table 11: Ofgem model credit metrics before financeability adjustments

EPN	6.0 cost of equity 75% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.6	3.5	3.4	3.2	3.0	2.6	2.5	2.4	3.0
FFO interest cover ratio (cash interest only)	4.2	4.1	3.9	3.7	3.4	3.0	2.9	2.8	3.5
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.32	1.28	1.23	1.16	1.10	1.00	0.98	0.95	1.13
FFO / Net Debt	14.3%	13.6%	12.9%	12.1%	10.9%	9.1%	8.6%	8.0%	11.2%
RCF / Net Debt	11.6%	10.9%	10.3%	9.4%	8.3%	6.6%	6.0%	5.5%	8.6%
Net Debt / Closing RAV	65%	66%	66%	67%	67%	69%	70%	71%	67%

LPN	6.0 cost of equity 74% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.7	3.5	3.4	3.2	3.0	2.7	2.4	2.6	3.1
FFO interest cover ratio (cash interest only)	4.3	4.1	3.9	3.7	3.5	3.1	2.8	3.0	3.5
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.31	1.26	1.22	1.15	1.09	0.99	0.97	1.11	1.14
FFO / Net Debt	14.7%	13.8%	12.9%	11.9%	10.9%	9.7%	7.9%	9.1%	11.4%
RCF / Net Debt	12.1%	11.2%	10.3%	9.3%	8.4%	7.2%	5.5%	6.4%	8.8%
Net Debt / Closing RAV	66%	66%	67%	68%	69%	70%	71%	66%	68%

SPN	6.0 cost of equity 77% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.4	3.3	3.1	2.9	2.7	2.5	2.7	2.5	2.9
FFO interest cover ratio (cash interest only)	3.9	3.8	3.6	3.4	3.1	2.9	3.1	2.9	3.3
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.30	1.25	1.19	1.12	1.06	0.96	1.11	0.99	1.12
FFO / Net Debt	12.9%	12.1%	11.4%	10.7%	9.4%	8.5%	9.7%	8.6%	10.4%
RCF / Net Debt	10.2%	9.5%	8.8%	8.2%	6.8%	6.1%	7.0%	6.0%	7.8%
Net Debt / Closing RAV	66%	67%	68%	69%	70%	71%	66%	67%	68%

The table shows that the PMICR metric is below 1.4 times for all licencees in all years. In addition, the notional gearing of 65% is exceeded in every year with the exception with exception of 2015/16 in EPN.

The tables below show the key rating agency metrics based on our own modelling utilising the same financing assumptions as applied in the Ofgem tables above. It shows that the adjusted ICR metric is significantly below the threshold for all licencees over ED1 and that for LPN and SPN they are operating at the top of the debt to RAV envelope. The analysis is in calendar years.

Table 12: UK Power Networks credit rating agency modelling with no financeability adjustments

Key Financial Ratios	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2016-2022 Average	Threshold
Moody's Net Debt/RAV										
EPN	65.2%	66.4%	65.7%	66.3%	66.2%	67.7%	68.5%	68.7%	67.1%	>60% – 75%; Baa
LPN	68.7%	70.8%	70.7%	71.8%	72.5%	74.1%	74.6%	74.9%	72.8%	>60% – 75%; Baa
SPN	69.5%	70.4%	70.5%	71.6%	71.6%	72.5%	72.7%	73.2%	71.8%	>60% – 75%; Baa
Average DNO	67.8%	69.2%	69.0%	69.9%	70.1%	71.4%	71.9%	72.3%	70.5%	>60% – 75%; Baa
Moody's Adjusted ICR										
EPN	1.53x	1.39x	1.20x	1.17x	1.14x	1.18x	1.15x	1.13x	1.19x	>1.4 – 2.0x; Baa
LPN	2.02x	1.77x	1.68x	1.54x	1.49x	1.40x	1.52x	1.52x	1.56x	>1.4 – 2.0x; Baa
SPN	1.77x	1.54x	1.42x	1.28x	1.28x	1.19x	1.14x	1.12x	1.28x	>1.4 – 2.0x; Baa
Average DNO	1.8x	1.6x	1.4x	1.3x	1.3x	1.3x	1.3x	1.3x	1.3x	>1.4 – 2.0x; Baa
UKPN Holdings	1.8x	1.6x	1.5x	1.5x	1.5x	1.4x	1.4x	1.4x	1.5x	>1.4 – 2.0x; Baa

Fitch's Key Financial Ratios	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2016-2022 Average	Threshold
Fitch's PMICR (excluding swap accretion)										
EPN	1.8x	1.4x	1.3x	1.2x	1.3x	1.3x	1.2x	1.2x	1.3x	>1.4x
LPN	1.5x	1.1x	1.1x	1.1x	1.0x	1.0x	1.2x	1.2x	1.1x	>1.4x
SPN	1.7x	1.3x	1.1x	1.1x	1.1x	1.1x	1.0x	1.0x	1.1x	>1.4x
Fitch's PMICR (including swap accretion)										
EPN	1.5x	1.3x	1.1x	1.1x	1.1x	1.1x	1.1x	1.1x	1.1x	>1.4x
LPN	1.4x	1.1x	1.1x	1.1x	0.9x	0.9x	1.1x	1.2x	1.0x	>1.4x
SPN	1.7x	1.3x	1.1x	1.1x	1.1x	1.1x	1.0x	1.0x	1.1x	>1.4x

The tables illustrate that the current investment plan would not be financeable under these assumptions. The options to address this are:

- Decrease the gearing to increase the WACC
- Apply transitional arrangements to the regulatory depreciation
- Combination of the above

Our preferred approach is to transition to a 45 year regulatory depreciation over one price control period. Our reasons for this are:

- We are currently operating at a gearing level of approximately 65% and this is deemed acceptable by the key rating agencies
- The proposed transitional method is an already accepted regulatory solution as it has been deployed in the transmission review

The tables below show both the Ofgem metrics and the Rating Agency metrics under this scenario.

Table 13 Rating Agency credit metrics after financeability adjustments – Ofgem model

EPN	6.0 cost of equity 68% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.6	3.6	3.6	3.5	3.3	3.0	2.9	2.8	3.3
FFO interest cover ratio (cash interest only)	4.2	4.2	4.2	4.0	3.9	3.4	3.4	3.3	3.8
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.33	1.29	1.25	1.19	1.14	1.04	1.03	1.00	1.16
FFO / Net Debt	14.5%	14.4%	14.3%	13.9%	13.0%	11.4%	10.9%	10.5%	12.9%
RCF / Net Debt	11.8%	11.7%	11.6%	11.2%	10.3%	8.7%	8.3%	7.9%	10.2%
Net Debt / Closing RAV	65%	65%	65%	65%	65%	66%	66%	67%	65%

LPN	6.0 cost of equity 68% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.7	3.7	3.6	3.5	3.3	3.1	2.8	2.7	3.3
FFO interest cover ratio (cash interest only)	4.3	4.3	4.2	4.0	3.9	3.6	3.2	3.2	3.8
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.32	1.27	1.24	1.18	1.12	1.03	1.02	0.99	1.15
FFO / Net Debt	15.0%	14.7%	14.2%	13.7%	13.0%	12.0%	10.2%	9.8%	12.8%
RCF / Net Debt	12.3%	12.0%	11.6%	11.0%	10.4%	9.4%	7.6%	7.3%	10.2%
Net Debt / Closing RAV	65%	65%	66%	66%	66%	67%	68%	69%	66%

SPN	6.0 cost of equity 68% slow money UKPN cost of debt assumptions								
	31/03/2016	31/03/2017	31/03/2018	31/03/2019	31/03/2020	31/03/2021	31/03/2022	31/03/2023	ED1 average
FFO interest cover ratio (including accretions)	3.4	3.4	3.3	3.3	3.1	2.9	2.9	2.8	3.1
FFO interest cover ratio (cash interest only)	4.0	3.9	3.9	3.8	3.5	3.3	3.3	3.2	3.6
Adjusted interest cover ratio (post-maintenance interest cover ratio)	1.30	1.26	1.22	1.16	1.10	1.00	1.00	0.97	1.13
FFO / Net Debt	13.2%	13.0%	12.8%	12.5%	11.4%	10.8%	10.5%	10.0%	11.8%
RCF / Net Debt	10.5%	10.3%	10.1%	9.9%	8.8%	8.2%	8.0%	7.5%	9.2%
Net Debt / Closing RAV	65%	66%	66%	66%	67%	68%	68%	69%	67%

The tables below show that the debt to RAV metric is now much closer, although still above, the notional gearing assumption. There has also been a marginal improvement in the adjusted ICR metric.

Table 74 Rating Agency credit metrics after financeability adjustments – UK Power Networks model

Key Financial Ratios	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	Threshold
Moody's Net Debt/RAV									
EPN	65.7%	67.5%	67.1%	67.6%	67.3%	68.3%	68.3%	67.3%	>60% – 75%; Baa
LPN	69.2%	71.8%	71.9%	73.2%	73.8%	74.9%	74.7%	74.0%	>60% – 75%; Baa
SPN	70.2%	71.8%	72.4%	73.6%	73.3%	73.7%	73.0%	72.1%	>60% – 75%; Baa
Moody's Adjusted ICR									
EPN	1.5x	1.4x	1.3x	1.3x	1.4x	1.5x	1.5x	1.6x	>1.4 – 2.0x; Baa
LPN	2.0x	1.8x	1.8x	1.7x	1.7x	1.7x	1.9x	2.0x	>1.4 – 2.0x; Baa
SPN	1.8x	1.6x	1.5x	1.5x	1.6x	1.6x	1.6x	1.7x	>1.4 – 2.0x; Baa
UKPN Holdings	1.8x	1.7x	1.6x	1.6x	1.6x	1.7x	1.7x	1.8x	>1.4 – 2.0x; Baa

Fitch's Key Financial Ratios	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	Threshold
Fitch's PMICR (excluding swap accretion)									
EPN	1.5x	1.1x	1.1x	1.1x	1.2x	1.3x	1.4x	1.6x	>1.4x
LPN	1.3x	0.8x	0.9x	1.0x	0.9x	1.0x	1.3x	1.5x	>1.4x
SPN	1.4x	0.9x	0.8x	0.9x	1.1x	1.1x	1.2x	1.3x	>1.4x
Fitch's PMICR (including swap accretion)									
EPN	1.3x	1.0x	0.9x	1.0x	1.0x	1.2x	1.2x	1.4x	>1.4x
LPN	1.2x	0.8x	0.9x	0.9x	0.9x	1.0x	1.3x	1.4x	>1.4x
SPN	1.4x	0.9x	0.8x	0.9x	1.1x	1.1x	1.2x	1.3x	>1.4x
Fitch's Adjusted Net Debt/ RAV (Y/E)									
EPN	63.9%	65.2%	65.4%	66.4%	66.5%	66.9%	66.6%	65.9%	<73%
LPN	63.2%	66.4%	66.8%	68.4%	69.3%	70.8%	70.8%	70.2%	<73%
SPN	65.1%	67.1%	67.9%	69.4%	69.3%	69.8%	69.1%	68.4%	<73%
Average DNO	64.1%	66.2%	66.7%	68.0%	68.4%	69.1%	68.9%	68.2%	<73%

The tables illustrates that the adjustments have ensured that the debt to RAV metrics are consistently below the threshold, although still at the upper end of the spectrum. The Adjusted ICR calculations are still weak but show a recovery towards the end of the RIIO period.

Equity dividend

We have set the dividend in all years and for all three networks at 5% of equity RAV. The UK electricity distribution networks are seen by the investing communities as stable cash-generative businesses which, failing under-performance, or a dramatic growth in capex (which is not the case in this price control) should be able to support a steady dividend in real terms. Furthermore a 5% dividend yield is in line with a peer group of UK utilities and below the average among a European peer group.

6 Financial policies

6.1 Pensions

6.1.1 Pension Costs

We are forecasting an increase in on-going pension costs through the RIIO-ED1 period through a combination of the following factors:

- Increase in on-going pension contributions for the defined pension schemes due to a combination of the aging profile of the membership and also the anticipated company contribution rates following the 2013 Valuations
- The introduction of automatic enrolment - employees are being enrolled into the defined contribution scheme in accordance with workplace pension reforms legislation. We have seen a very low opt out rate and this has been reflected in our plan. However, as the increased membership is through a personal pension arrangement we have not predicted an associated increase in our other costs

6.1.2 Deficits

As with most other UK pensions schemes we have seen pension deficits rise since the last valuation for the defined benefit schemes. Therefore we start RIIO-ED1 with larger deficits then forecasted following the 2010 Valuations.

The increased deficit figures are a direct result of current market conditions, in particular low gilt yields, as the Trustees' investment strategy has performed well.

Opinion differs across the financial industry insofar as the speed and degree of recovery of gilt yields and therefore deficit. Using the current mark to market approach to liability valuation can create significant fluctuation in funding levels between valuations.

Our business plan assumes that the roll forward deficit at 31/12/2012 will continue to be recovered over the remaining years of the current recovery plan ending in 2025 for both Established and Incremental deficits.

6.1.3 De-risking

UK Power Networks has limited influence over many of the Trustee decisions, particularly investment decisions. The ESPS Trustees have recently launched a de-risking programme with a target date of 2026 to coincide with the end of their Deed of Undertaking negotiated at the time of the networks sale from EDF Energy.

The Trustees did consult with UK Power Networks and a de-risking strategy was developed reflecting UK Power Networks' feedback that would:

- satisfy the Trustees objective of self-sufficiency by 2026 (and therefore significantly reduce any on-going funding strain on future generations of energy consumers)
- prevent an immediate increase in costs in current consumers

This was achieved by developing a series of outperformance funding triggers based upon a self-sufficiency funding target. These triggers, once hit, instigate a switch from growth to matching assets.

As investment outperformance is funding the de-risking it is understood that current consumers do bear an additional burden to support de-risking. However, the long term objective of self-sufficiency would have a greater benefit on consumers in the longer term by reducing the likelihood of future deficits once fully de-risked. Additionally, greater diversification has also been incorporated into the investment portfolios to mitigate the potential investment downside whilst retaining the same overall investment target in the short to medium term.

Again, we feel that not only does that protect the scheme membership but also consumers insofar as they have more protection from increased deficits arising from investment underperformance.

The Trustees of the UK Power Networks Pension Scheme have considered de-risking but following discussions with UK Power Networks have not yet implemented a de-risking strategy. It is felt that removing risk from the investment portfolio at this stage of the Scheme's maturity (in a similar way to ESPS) was not in line with comparable schemes or in the best interests of the consumers at this time. The Trustees will of course continue to monitor this.

6.2 Taxation

Our business plan is consistent with the RIIO-ED1 principals and Ofgem proposed policies.

7 Summary

The key criteria we have used in assessing the financeability of our business plans are:

- Provides acceptable credit and equity metrics, in particular we target ratings that meet BBB+ (Baa1)
- Provides appropriate return to investors through a combination of allowed return on equity and a plausible range of outperformance on incentive and efficiency opportunities
- Meets investor expectations over the long term, given uncertainty over long-term usage of the electricity distribution network
- Complies with Ofgem's stated policies

Our plan includes a real cost of equity at 6.0% as this is Ofgem's current central assumption. We are concerned that there is little detail to support the build-up of Ofgem's calculation and in particular how the cost of embedded debt has been allowed for. We calculate that the debt underperformance in ED1 would add 0.55% to the cost of equity.

In order to maintain financeability, given Ofgem's policy to move to longer asset lives in the RAV, we have undertaken modelling to derive the most appropriate mix of transitional measures which allow each of networks to meet the criteria shown above. We have looked closely at each network and sought to apply a tailored approach which best serves the stakeholders in each case. Our proposed approach is as follows:

- Transition to 45 year regulatory asset lives over the ED1 period for all three networks
- Adopt a 32%:68% between fast and slow money for all three networks.
- Adopt the following revenue profiling assumptions for each network to address deteriorating credit metrics towards the end of ED1

Table 5 Summary of Po and X

	EPN	LPN	SPN
Po	5%	12%	13%
Annual X	2.0%	1.8%	2.7%

- Maintain notional gearing of 65% across our three networks

This package includes an assumption that an efficient company is able to earn a maximum Return on Regulated Equity (RORE) which is greater than 10% in line with Ofgem's expectations.

8 Appendices

A.1 RoRE factors with classifications by magnitude of impact, variability and priority to investigate

RoRE calculation factors	Magnitude of Impact	True Variability	Priority to investigate further	Rationale / Key Assumptions
IQI cost delta				
Allowed load related capex	High	None	Low	Allowed costs are fixed
Allowed non-load related capex	High	None	Low	Allowed costs are fixed
Allowed trees opex	Medium	None	Low	Allowed costs are fixed
Allowed faults opex	High	None	Low	Allowed costs are fixed
Allowed I&M opex	High	None	Low	Allowed costs are fixed
Allowed closely associated indirects	High	None	Low	Allowed costs are fixed
Achieved load related capex	High	High	High	Peak MW demand forecasts used to derive low, medium and high load related scenarios
Achieved non-load related capex	High	High	High	Use RIGs Forecast submission as baseline for Smart Metering with range of uptake
Achieved trees opex	Medium	Low	Low	Low variability around tree cutting costs
Achieved faults opex	High	High	High	Historic fault rate data can be used to understand the variability in volume of faults
Achieved I&M opex	High	Low	Medium	Low variability around I&M costs
Achieved closely associated indirects	High	Medium	High	Assumed 1/3 ratio against direct costs, there is uncertainty around these as a result of direct cost uncertainties
Incentive sharing factor	Medium	None	Low	Different DPCR5 and RIIO-ED1 factors
Business support costs delta				
Allowed business support	High	None	Low	Allowed costs are fixed

costs				
Achieved business support costs	High	Low	Medium	Variability assumed to be immaterial
IT expenditure	High	Medium	High	Significant less of IT spend, of which there is some uncertainty
Exit charges	High	Low	Medium	Exit charge costs significant, but well understood
Connections	High	Low	Medium	Connections charges significant, but well understood
Incentive sharing factor	Medium	None	Low	Fixed
Output incentives delta				
CI target for incentivisation		Low		Little uncertainty over CI target
CI achieved		High		Historic performance can be used to predict the variation of future performance
Incentive rate per CI saved	Low	None	Medium	Incentive rate assumed not to change
CML target for incentivisation		Low		Little uncertainty over CML target
CML achieved		High		Historic performance can be used to predict the variation of future performance
Incentive rate per CML saved	Medium	None	High	Incentive rate assumed not to change
BMoCS DNO ranking		High		Highly unknown how DNO performance / ranking will correspond to financial incentive
BMoCS incentive capping	Medium	Low	High	Capping of incentive well known
Financeability delta				
Regulatory cost of debt	High	Medium	High	Significant uncertainty in how the market cost of debt will change over RIIO-ED1
UKPN cost of debt	Medium	Low	Low	UKPN cost of debt is well known with little variability
Average net debt	Medium	None	Low	Net debt known
Vanilla WACC	Low	None	Low	Fixed
Tax rate	Medium	Low	Low	Tax rate well understood
Regulatory Equity	Medium	Low	Low	Regulatory equity well known
Baseline pensions expenditure	High	None	Low	Baseline pensions costs known
Incremental pensions expenditure	High	Medium	High	Incremental pensions costs less predictable

A.2 Statutory and regulatory totex calculations

	EPN		Statutory definition							Regulatory Definition					
Per Regulatory Accounts		EPN	2007/8	2008/9	2009/10	2010/11	2011/12	Average	Notes	2007/8	2008/9	2009/10	2010/11	2011/12	Average
capex	Gross network		289.6	345.9	340.5	319.0	288.1								
	Contributions		-71.5	-86.1	-63.3	-69.3	-66.9								
	Non Op Capex		14.8	13.3	16.8	5.9	24.1		IT, Tools, Property, Transport						
	Regulatory accounts fixed assets schedule		232.9	273.1	294	255.6	245.3								
	Remove														
	Capitalised Interest		0.0	0.0	-6.4	-5.8	-8.5								
	Metering		-12.0	-8.3	-2.9	-3.7	-0.6		Excluded service ouside price control						
	Security & Undergrounding			-0.6	-0.7				Logged up items						
	Connections					2.3	-3.5		Generation & DR5 Sole use outside Price Control						
	Regulatory adjustments for disallowed margins et		-0.4	-0.3	-0.2	0.0	-2.5		Cost removed for fines,penalties,margin etc						
			220.5	263.9	283.8	248.4	230.2		**Slow Pot**	184.9	225.1	243.7	252.2	217.6	
	Cost of sales		8.6	9.7	16.4	14.8	18.7								
	Distribution Costs		168.1	197.6	210.2	286.8	230.9								
	Depreciation		-50.3	-57.1	-63.5	-118.3	-67.4		Statutory depreciation outside scope						
	Admin costs		1.5	1.5	2.8	2.3	3.1								
	Regulatory accounts Opex excluding Depn		127.9	151.7	165.9	185.6	185.3								
	Remove:														
	Metering		-12.6	-11.4	-9.8	-6.8	-2.9		Excluded service outside price control						
	IFI		-2.1	-1.5	-1.7	-1.5	-1.2		Subject to separate incentive						
	LCN				0.0	-0.3	-0.5		Subject to separate incentive						
	LCN balancing						-7.7		Only from 2011/12						
	NTR costs			-17.6	-14.4	-16.7	-16.3		Excluded service outside price control						
	Barber provision release			10.9					One off affecting EPN/LPN only						
	Provisions		0.6	-1.5	0.0	-2.4	0.1		Non Cash item						
	Operational Rates		-25.7	-26.7	-28.0	-31.4	-34.1		Passthrough						
	PES Licence		-1.6	-1.6	-1.7	-1.4	-1.7		Passthrough						
	Bad Debts		0.0	0.0	0.0	0.0	-1.7		Passthrough						
	Exit Charges		-8.6	-9.7	-16.4	-14.8	-16.9		Passthrough						
	wheeled units		-0.5	-0.6	-0.6	-0.6	-0.6		Passthrough						
	Income offset against costs for Reg Purposes		-6.3	-11.7	-12.1	-7.8	-8.2		Cable Damage income & ES4/ES7 adjustments						
	Regulatory adjustments for disallowed margins et		-1.3	-3.3	-0.1	-7.0	-7.0		Cost removed for fines,penalties,margin etc						
			69.8	77.0	81.1	94.9	86.5	409.3	**Fast Pot**	105.4	115.8	121.2	91.0	99.1	532.5
Total			290.3	340.9	364.9	343.2	316.7	1656.0	Total	290.3	340.9	364.9	343.2	316.7	1656.0
Opex %			24%	23%	22%	28%	27%	25%		36%	34%	33%	27%	31%	32%

Per Regulatory Accounts		LPN	2007/8	2008/9	2009/10	2010/11	2011/12	Average	Notes	2007/8	2008/9	2009/10	2010/11	2011/12	Average
capex	Gross network		181.8	207.8	209.9	202.4	187.8								
	Contributions		-57.8	-75.3	-79.6	-68.2	-62.2								
	Non Op Capex		8.3	8.8	6.9	5.0	16.0		IT, Tools, Property, Transport						
	Regulatory accounts fixed assets schedule		132.3	141.3	137.2	139.2	141.6								
	Remove														
	Capitalised Interest		0.0	0.0	-2.6	-3.7	-5.4								
	Metering		-2.2	-2.1	-2.6	-1.8	-0.7		Excluded service ouside price control						
	Security & Undergrounding		-0.4	-3.0					Logged up items						
	Connections					0.2	-0.6		Generation & DR5 Sole use outside Price Control						
	Regulatory adjustments for disallowed margins et		-0.3	-0.6	-0.7	0.5	-1.0		Cost removed for fines,penalties,margin etc						
			129.4	135.6	131.3	134.5	133.9		**Slow Pot**	112.2	115.6	110.4	129.4	114.4	
	Cost of sales		12.0	18.2	18.7	26.5	21.7								
	Distribution Costs		115.7	154.5	150.9	209.4	147.0								
	Depreciation		-38.4	-42.7	-46.2	-100.3	-40.8		Statutory depreciation outside scope						
	Admin costs		0.8	2.3	2.5	1.6	1.7								
	Regulatory accounts Opex excluding Depn		90.1	132.3	125.9	137.2	129.6								
	Remove:														
	Metering		-5.6	-5.4	-4.0	-2.6	-1.9		Excluded service outside price control						
	IFI		-2.1	-1.4	-0.8	-1.0	-0.7		Subject to separate incentive						
	LCN				0.0	-1.4	-7.7		Subject to separate incentive						
	LCN balancing						2.2		Only from 2011/12						
	NTR costs			-29.3	-23.7	-16.3	-19.8		Excluded service outside price control						
	Barber provision release			5.8					One off affecting EPN/LPN only						
	Provisions		0.3	-1.2	3.5	-1.0	-0.1								
	Operational Rates		-23.2	-24.1	-25.3	-24.2	-24.0		Passthrough						
	PES Licence		-1	-1	-1.1	-0.9	-1.1		Passthrough						
	Bad Debts		0	0	0.0	0.0	-2.1		Passthrough						
	Exit Charges		-12	-18.2	-18.7	-26.5	-19.6		Passthrough						
	wheeled units		0	0	0.0	0.0	0.0		Passthrough						
	Income offset against costs for Reg Purposes		-4.2	-7.5	-9.2	-7.3	-7.4		Cable Damage income & ES4/ES7 adjustments						
	Regulatory adjustments for disallowed margins et		0.5	0.6	1.6	-3.1	-3.9		Cost removed for fines,penalties,margin etc						
			42.8	50.6	48.2	52.9	43.6	238.0	**Fast Pot**	59.9	70.6	69.1	58.0	63.0	320.7
Total			172.2	186.2	179.5	187.4	177.5	902.6	Total	172.2	186.2	179.5	187.4	177.5	902.6
Opex %			25%	27%	27%	28%	25%	26%		35%	38%	39%	31%	36%	36%

Per Regulatory Accounts		SPN	2007/8	2008/9	2009/10	2010/11	2011/12	Average	Notes	2007/8	2008/9	2009/10	2010/11	2011/12	Average
capex	Gross network		173.4	216.4	233.5	214.3	197.3								
	Contributions		-42.9	-51.3	-48.0	-39.2	-38.0								
	Non Op Capex		6.9	5.2	6.5	5.8	14.6		IT, Tools, Property, Transport						
	Regulatory accounts fixed assets schedule		137.4	170.3	192	180.9	173.9								
	Remove														
	Capitalised Interest		0	0	-1.4	-1.8	-2.3								
	Metering		-3.3	-3.7	-1.8	-1.8	0.0		Excluded service ouside price control						
	Security & Undergrounding			-1.5	-3.0				Logged up items						
	Connections					-0.2	-0.4		Generation & DR5 Sole use outside Price Control						
	Regulatory adjustments for disallowed margins et		-0.1	-0.1	-0.1	0.1	-1.9								
			134.0	165.0	185.7	177.2	169.3		**Slow Pot**	111.4	139.0	164.9	168.2	152.6	
	Cost of sales		7.5	8.3	9.0	9.5	10.6								
	Distribution Costs		97.6	122.6	127.1	176.9	134.9								
	Depreciation		-36.3	-39.5	-42.9	-91.1	-41.2		Statutory depreciation outside scope						
	Admin costs		0.5	1.4	2.7	1.3	1.9								
	Regulatory accounts Opex excluding Depn		69.3	92.8	95.9	96.6	106.2								
	Remove:														
	Metering		-4.2	-4.6	-2.4	-2.4	-1.4		Excluded service outside price control						
	IFI		-1.3	-0.9	-0.8	-0.9	-0.7		Subject to separate incentive						
	LCN				0.0	-0.2	-0.2		Subject to separate incentive						
	LCN balancing						-4.9		Only from 2011/12						
	NTR costs			-6.4	-8.3	-7.3	-6.6		Excluded service outside price control						
	Barber provision release								One off affecting EPN/LPN only						
	Provisions		-0.9	-1.3	0.7	-1.5	-6.8		Non Cash item						
	Operational Rates		-9.7	-7.6	-7.6	-8.5	-10.2		Passthrough						
	PES Licence		-1	-1	-1.1	-0.9	-1.1		Passthrough						
	Bad Debts		0	0	0.0	0.0	-0.6		Passthrough						
	Exit Charges		-7.5	-8.3	-9.0	-9.5	-10.0		Passthrough						
	wheeled units		0	0	0.0	0.0	0.0		Passthrough						
	Income offset against costs for Reg Purposes		-3.0	-7.2	-9.7	-7.0	-6.5		Cable Damage income & ES4/ES7 adjustments						
	Regulatory adjustments for disallowed margins et		-3.7	-1.2	-6.8	-4.5	-6.1		Cost removed for fines,penalties etc						
			38.0	54.4	50.8	54.0	51.1	248.3	**Fast Pot**	60.5	80.3	71.6	63.0	67.8	343.3
Total			172.0	219.4	236.5	231.2	220.4	1079.5	Total	172.0	219.4	236.5	231.2	220.4	1079.5
Opex %			22%	25%	21%	23%	23%	23%		35%	37%	30%	27%	31%	32%

A.3 Oxera RIIO-ED1 consultation on strategy

(See next page)

A.4 Oxera RIIO-ED1 risk assessment framework

(Follows Oxera RIIO-ED1 consultation on strategy appendices)

Oxera

RIIO-ED1 consultation on strategy

Financial issues

Prepared for
Energy Networks Association

November 16th 2012

Executive summary

This report was commissioned by the Energy Networks Association as a response to the consultation on the strategy for the next electricity distribution price control (RIIO-ED1).[1]

The strategy consultation sets out Ofgem's proposed framework for determining efficient financing costs in RIIO-ED1. The key proposals in relation to the allowed return include:

– an initial cost of equity range of 6.0–7.2% based primarily on evidence from the CAPM;
– a cost of debt allowance updated annually based on movements in the simple ten-year trailing average of Ofgem's measure for the market cost of debt.

The proposals are largely identical to the strategy decision for the ongoing transmission and gas distribution price control reviews (RIIO-T1 and GD1 respectively). Ahead of the strategy consultation, Oxera produced a report on behalf of the Energy Networks Association which suggested how the RIIO-T1 and GD1 approach could be refined for RIIO-ED1.[2] This response complements the September report by considering some specific areas of Ofgem's strategy consultation.

Cost of equity

The proposed initial cost of equity range of 6.0–7.2% is the same as the cost of equity range in the RIIO-T1/GD1 strategy decision.

– Considering the overlap between RIIO-ED1 and RIIO-T1/GD1, to ensure consistent investment and consumption choices across the energy networks, using the same cost of equity range as in RIIO-T1/GD1 is appropriate.

– The proposed ranges for the risk-free rate and the equity risk premium (ERP), of 1.7–2.0% and 4.75–5.5% respectively, reflect a longer-term view of capital market data, which is appropriate, given a move to a longer price control and challenges in interpreting current market data. Estimates towards the upper end of the proposed ranges are broadly consistent with recent regulatory precedent.

The precise number for the allowed return on equity for each individual DNO will depend on the details of their business plans. However, the proposed values for the risk-free rate and the ERP in the RIIO-T1/GD1 Initial Proposals, the settlement for the last distribution price control (DPCR5), and initial evidence that risk is likely to be higher in RIIO-ED1 than in DPCR5,[3] suggest that point estimates higher than 6.7% are likely to be more plausible.

Cost of debt

To ensure that efficient debt costs are recoverable in RIIO-ED1, it is important to analyse the impact of Ofgem's debt indexation proposals on risk and financeability taking into account the specific characteristics of the electricity distribution sector.

The strategy consultation carries over the same debt indexation assumptions from RIIO-T1/GD1 to RIIO-ED1 without providing any DNO-specific analysis. In addition, as outlined in

[1] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th.
[2] Oxera (2012), 'Determining efficient financing costs for RIIO-ED1', prepared for the Energy Networks Association, September 3rd.
[3] Ibid.

Oxera's September report, a number of issues with the approach used in RIIO-T1/GD1 remain outstanding and are just as valid in the context of RIIO-ED1.

A review of the arguments put forward in the strategy consultation to address some of these issues suggests that there are still a number of shortcomings with the proposed approach for remunerating debt costs. It is recommended that these issues be given further consideration ahead of the RIIO-ED1 strategy decision.

– **Compensation for residual cost of debt risk**. The principle behind debt indexation is to reduce the risk of error in the estimate of the cost of debt, and hence reduce the need to provide a margin ('headroom') in the cost of debt allowance by setting it above the central estimate of the efficient cost of debt, inclusive of debt issuance costs. Ofgem proposes to remove this margin completely under indexation, notwithstanding the fact that the risk of error will not reduce to zero, and in some cases will not reduce materially compared with a fixed cost of debt allowance.

    – All companies will be exposed to risk due to both intra-year volatility in yields and a time-varying inflation risk premium.

    – For an average DNO, debt indexation leads to only a modest reduction in risk compared with a fixed cost of debt allowance, since only a small proportion of the existing debt needs refinancing in RIIO-ED1. For a number of companies with very low refinancing needs, debt indexation may actually increase risk.

– **Risk of under-recovery of efficiently incurred debt costs**. Given the historical downward trend in the cost of debt and current low levels of yields, there is a material risk of under-recovery of efficiently incurred debt costs in RIIO-ED1. While the risk of divergence between the existing and allowed costs of debt is present in all price controls, in previous price controls companies were compensated for this risk of divergence through a margin in the allowed cost of debt. In addition, the proposed design of the index, combined with the current market environment, leads to a higher probability of under-recovery than in previous price controls.

– **Allowance for debt issuance costs**. To ensure that efficient debt costs, including debt issuance costs, are recoverable regardless of the market conditions or other unforeseen circumstances (such as the impact of Solvency II and changes in the index composition), a separate allowance for debt issuance costs would be more appropriate than the current proposals.

Ofgem's duty to allow companies to finance their functions suggests that the above factors cannot be disregarded. It is important that the debt indexation proposals appropriately reflect the risk of error between the allowed and actual cost of debt and provide adequate protection against under-recovery of efficiently incurred debt costs, inclusive of debt issuance costs. This can be achieved either by providing a suitable margin in the allowed return (on either debt or equity) or, where appropriate, by modifying the debt index or supplementing it with a mechanism to avoid undue exposure to risk.

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1 Introduction

This report was commissioned by the Energy Networks Association as a response to the consultation on the strategy for the next electricity distribution price control (RIIO-ED1).[4]

The strategy consultation sets out Ofgem's proposed framework for determining efficient financing costs in RIIO-ED1. The key proposals in relation to the allowed return include:

– an initial cost of equity range of 6.0–7.2% based primarily on evidence from the CAPM;
– a cost of debt allowance updated annually based on movements in the simple ten-year trailing average of Ofgem's measure for the market cost of debt.

The proposals are largely identical to the strategy decision for the ongoing transmission and gas distribution price control reviews (RIIO-T1 and GD1 respectively). Ahead of the strategy consultation, Oxera produced a report on behalf of the Energy Networks Association which suggested how the RIIO-T1 and GD1 approach could be refined for RIIO-ED1.[5] This response complements the September report by considering some specific areas of Ofgem's strategy consultation.

The rest of this report is structured as follows:

– section 2 comments on the proposed initial range for the cost of equity, with a focus on the risk-free rate and the equity risk premium (ERP) parameters;
– section 3 discusses the debt indexation proposals.

[4] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th.
[5] Oxera (2012), 'Determining efficient financing costs for RIIO-ED1', prepared for the Energy Networks Association, September 3rd.

2 Cost of equity

In the strategy consultation Ofgem proposes an initial cost of equity range of 6.0–7.2%. This range is derived using a CAPM-based approach: 'ie looking at each of the components of the cost of equity'—the risk-free rate, ERP and the equity beta.[6]

The proposed cost of equity range is the same as the cost of equity range in the RIIO-T1/GD1 strategy decision.

– Considering the overlap between RIIO-ED1 and RIIO-T1/GD1, to ensure consistent investment and consumption choices across the energy networks, using the same range as in RIIO-T1/GD1 is appropriate.

– The proposed ranges for the risk-free rate and the ERP, of 1.7–2.0% and 4.75—5.5% respectively, reflect a longer-term view of capital market data, which is appropriate, given a move to a longer price control period and challenges in interpreting current market data. Estimates towards the upper end of the proposed ranges are broadly consistent with recent regulatory precedent.

The precise number for the allowed return on equity for each individual DNO will depend on the details of their business plans. However, the proposed values for the risk-free rate and the ERP in the RIIO-T1/GD1 Initial Proposals, the settlement from the last electricity price control (DPCR5), and initial evidence that risk is likely to be higher in RIIO-ED1 than in DPCR5,[7] suggest that point estimates higher than 6.7% are likely to be more plausible.

2.1 Overall approach to market parameters

It is unusually difficult to apply the CAPM to current capital market data. A number of factors contribute to this:

– the aftermath of the most severe financial crisis in recent decades, with capital markets continuing to go through periods of high volatility;
– loose monetary policy on an unprecedented scale, including several rounds of quantitative easing (QE) by the Bank of England;
– increased uncertainty around key economic fundamentals, such as output and inflation;
– continuing concerns about the fiscal sustainability of a number of governments around the world, particularly in the eurozone;
– changes in the regulation and investment strategies of financial institutions, such as the impact of pension fund investment on index-linked gilt yields.

These factors have led to a marked divergence between short-term estimates of the CAPM market parameters—namely, the risk-free rate and the ERP—and longer-term estimates. This means that interpreting current market evidence is very challenging, especially in a context where the regulator needs to forecast a cost of equity for the duration of the 8-year price control.

[6] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.35.
[7] Oxera (2012), op. cit.

In the strategy consultation, Ofgem proposes an initial cost of equity range of 6.0–7.2% (Table 2.1). This is the same as the ranges initially proposed in the RIIO-T1/GD1 strategy decision.[8]

Table 2.1 Initial range for the cost of equity

Component	RIIO-ED1	RIIO-GD1	RIIO-T1 (Gas)	RIIO-T1 (Electricity)	DPCR5
Risk-free rate (%)	1.7–2.0	2.0	2.0	2.0	2.0
ERP (%)	4.75–5.5	5.25	5.25	5.25	5.25
Equity beta	0.90–0.95	0.90	0.91	0.95	0.90
Cost of equity (post-tax) (%)	**6.0–7.2**	**6.7**	**6.8**	**7.0**	**6.7**

Note: The values for RIIO-GD1 and RIIO-T1 are based on Initial Proposals.
Source: Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, Figure 2.7, p. 20.

As RIIO-ED1 substantially overlaps with the RIIO-T1/GD1 price controls, ensuring that investment and consumption choices are not distorted across different forms of energy and parts of the value chain requires the financial parameters for the different price controls to be determined using similar fundamental assumptions. Therefore, it seems appropriate to use the same initial range for the cost of equity at this stage in the process.

Ofgem is not constrained to update its parameters mechanically to account for any market developments between the strategy consultation and the strategy decision. Given that the start of the price control is more than two years away, very short-run market movements are unlikely to provide much new guidance on what the allowed return on equity should be for an eight-year period from April 2015.

Although the precise cost of equity for individual DNOs will depend on the details of their business plans, the RIIO-T1/GD1 Initial Proposals use a risk-free rate and ERP estimate of 2.0% and 5.25% respectively—which is the same as for DPCR5 (Table 2.1). Ensuring consistent signals for investment and consumption across the energy sectors suggests that it would be appropriate to use market parameters for RIIO-ED1 similar to RIIO-T1/GD1. Furthermore, initial assessment suggests that risk for RIIO-ED1 is likely to be higher than for DPCR5.[9] Therefore, in practice, while the overall proposed range is likely to capture reasonable estimates of the allowed return on equity for RIIO-ED1, point estimates higher than 6.7% are likely to be more plausible.

2.2 Risk-free rate

The risk-free rate range proposed in the strategy consultation is higher than spot yields on index-linked gilts. In the regulatory context, it is appropriate to set the regulatory allowance for the risk-free rate higher than the spot yield in order to reflect uncertainty over future levels of the risk-free rate, and hence the required return on equity.

– This can be viewed as the 'insurance premium' that a company requires for bearing the risk of a variable cost of equity relative to a fixed allowance.

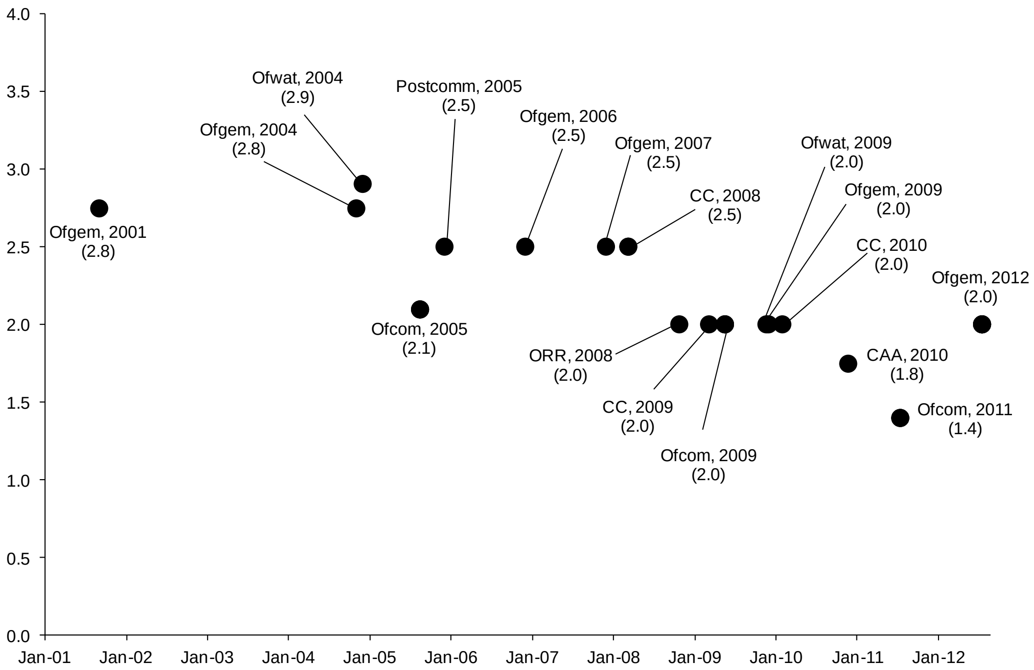
– Additionally, setting the regulatory allowance above the spot yield can reflect a view that the costs of overestimating the risk-free rate (and hence overcharging consumers) are smaller than the costs of underestimation (creating an underinvestment problem).

[8] Ofgem (2011), 'Decision on strategy for the next transmission and gas distribution price controls—RIIO-T1 and GD1 Financial issues', March 31st.
[9] Oxera (2012), op. cit. The Energy Networks Association is undertaking further work on developing a common risk assessment framework.

As shown in Figure 2.1, a risk-free rate range of 1.7–2.0% is generally in line with recent regulatory precedent. In fact, most regulators (with the exception of Ofcom) have adopted values closer to 2%.

Regulators have typically looked beyond short-term market fluctuations in order to achieve a degree of regulatory consistency across price reviews and ensure that their decisions are not unduly influenced by very short-term market movements. This is prudent, especially when faced with unusual market conditions, such as those that have prevailed since the start of the financial crisis in 2007.

Figure 2.1 Real risk-free rate regulatory determinations



Note: CC, Competition Commission. To facilitate comparability of regulatory precedents across parameters, in determinations where a nominal rate of return is applied, as in telecoms, a real risk-free rate was estimated using inflation assumptions.
Source: Regulatory determinations and Oxera analysis.

The only regulator recently to adopt a risk-free rate materially below 2% is Ofcom.[10] However, the relevance of its decision in the current context is limited by the following factors.

– Ofcom's determination applies to a three-year rather than an eight-year price control period, suggesting that the risk of error in the cost of capital estimate is significantly lower.

– Unlike other regulators, Ofcom does not have an explicit financing duty,[11] suggesting that the risk of underinvestment might play a slightly lesser role in setting the financial parameters of a price control.

For RIIO-ED1, it is appropriate to set the regulatory allowance for the risk-free rate higher relative to spot yields than in the past.

[10] Since the RIIO-T1 and GD1 strategy decision, Ofcom has made two risk-free rate determinations: one in July 2011 and one in April 2012. The decision in April 2012 was based on the value used in July 2011 and did not consider new evidence since that decision. Ofcom (2011), 'WBA charge control. Charge control framework for WBA Market 1 services', July; Ofcom (2012), 'Wholesale ISDN30 Price Control', April.

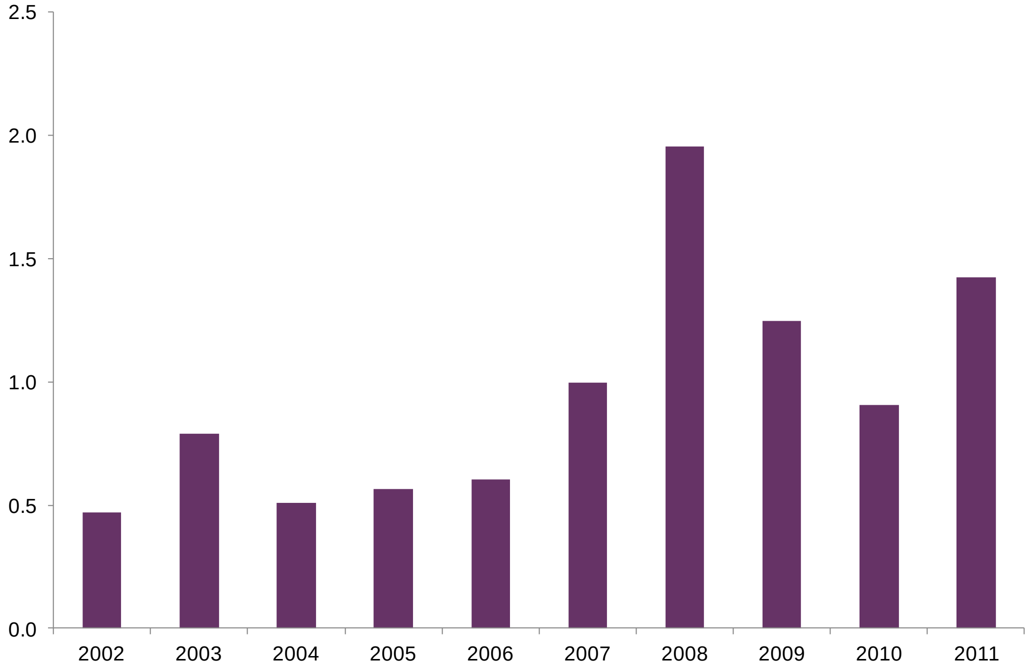
[11] Communications Act 2003, Section 3(1).

– A move from a five- to an eight-year price control period exposes companies to greater capital market uncertainty than in previous controls and in comparison to other sectors.

– Measures of the risk-free rate continue to be more volatile in the context of elevated capital market uncertainty than in the past (see Figure 2.2 below).

– Spot yields are at historically low levels, suggesting that the potential for further declines is limited, whereas there is potential for large increases.

Figure 2.2 Difference between maximum and minimum of daily ten-year index-linked gilt yield by calendar year (%)



Source: Datastream, Oxera.

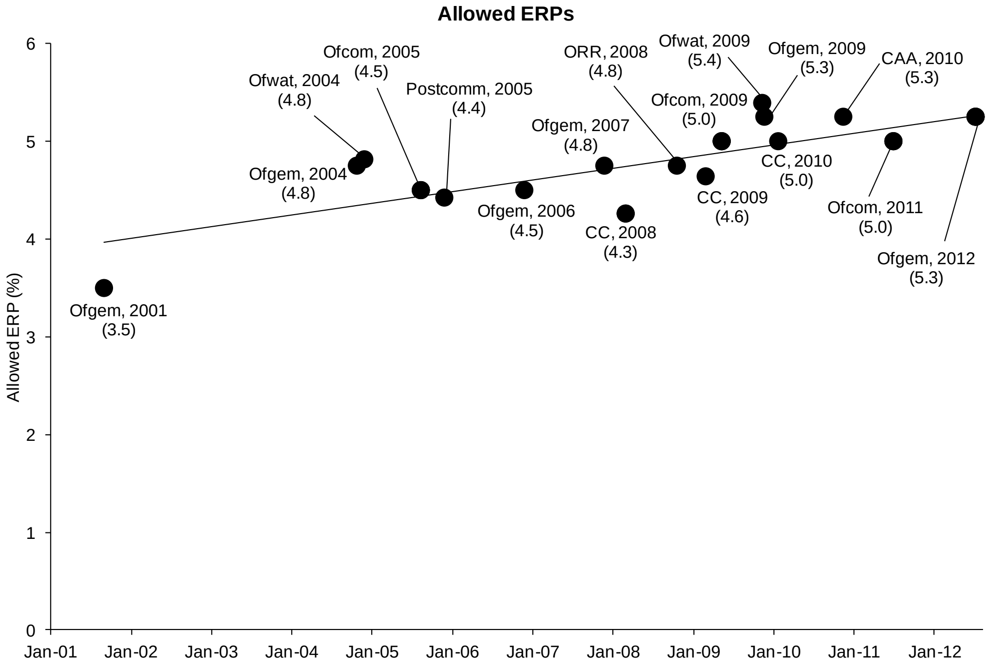
The higher probability of interest rates increasing, rather decreasing, appears to be acknowledged by Ofgem, and is indeed reflected in its choice of an upper bound for the risk-free rate range of 2%.[12] This is a reasonable approach in the current context.

2.3 Equity risk premium

The ERP is not directly observable, and setting a regulatory allowance for the ERP also requires a degree of judgement. Estimates of the ERP towards the upper end of Ofgem's proposed range of 4.75–5.5% are generally in line with recent regulatory precedent. As shown in Figure 2.3, regulatory determinations for the ERP have generally followed an upward trend in recent years, partially to reflect the impact of the financial crisis.

[12] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.50.

Figure 2.3 ERP regulatory determinations

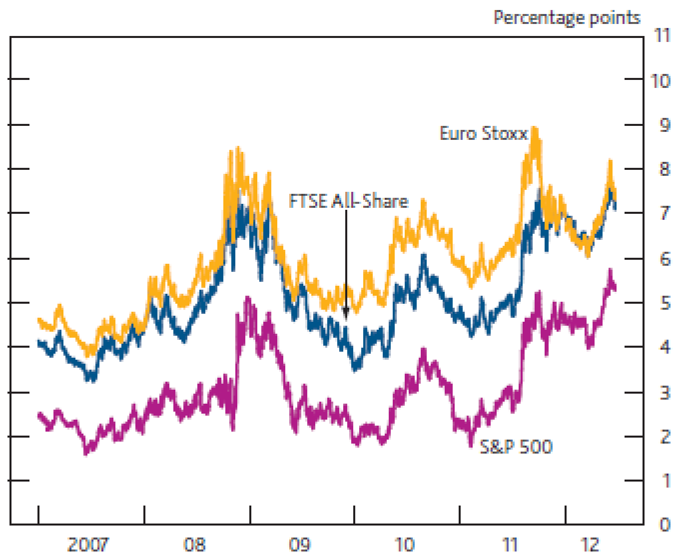


Source: Various regulatory determinations.

Based on forward-looking measures of the ERP (see Figure 2.4 below), an allowance higher than 5.25% could be supported. The estimates of the ERP produced by the Bank of England have:

– trended upwards since 2007;
– stabilised at about 7% in the past 18 months;
– risen above 7% on three occasions in the past five years.

Figure 2.4 Bank of England estimates of the ERP



Sources: Bloomberg, Thomson Reuters Datastream and Bank calculations.

(a) As implied by a multi-stage dividend discount model.

Source: Bank of England (2012), 'Financial Stability Report', p. 10, Chart 1.11, June.

Similarly, forward-looking estimates of the ERP produced by Deutsche Bank as at the end of August 2012 are above 8%—notably higher than DMS estimates.[13]

In other words, an ERP range of 4.75–5.5% is considerably lower than most recent forward-looking estimates. However, this is consistent with Ofgem's approach of taking a longer-term view of the risk-free rate. Taking into account the trend of recent regulatory determinations, estimates near the upper end of the 4.75–5.5% range appear appropriate.

2.4 Equity beta

A detailed review of Ofgem's equity beta assumptions is outside the scope of this response. At this stage, this response covers two specific areas of risk assessment in the strategy consultation: the impact of higher cash-flow duration, and the overall framework for assessing risk.

2.4.1 Duration of cash flows

One specific factor that could affect business risk in RIIO-ED1, and which is discussed in the strategy consultation, is the increase in the duration of cash flows following Ofgem's decision to increase regulatory asset lives for new assets in electricity distribution. The strategy consultation suggests that this is unlikely to be a material factor in setting the cost of equity for RIIO-ED1, largely on the basis of evidence produced previously by Europe Economics.[14]

Oxera has previously explained the theoretical relationship between cash-flow duration and required returns, drawing on established principles from the finance literature, and why in the case of regulated utilities the required return is likely to increase if cash-flow duration increases.[15] In simple terms, the 'duration effect' can be broken down into two parts: the impact of duration on the sensitivity of expected returns to the real risk-free rate (the 'term premium' effect); and the impact of duration on the sensitivity of expected returns to the Sharpe ratio (the 'beta' effect). The duration effect is unlikely to be picked up by the standard CAPM, which is a one-period model that assumes no variation over time in either the real risk-free rate or the ERP.

An approximation of the net impact of the term premium component on the overall weighted average cost of capital (WACC) for a regulated energy network can be given by considering the impact for a 100% equity-financed company. On this basis, the impact on the cost of capital would be to increase the risk-free rate by the term premium and decrease the risk premium by the product of the term premium and the asset beta. For the UK, using a proxy for the term premium based on the difference between realised returns on long-maturity government bonds compared with short-maturity bonds over the period 1900–2011 gives an estimate of 1.2% for the term premium.[16] Assuming an asset beta of 0.4, an effect of the term premium on the cost of capital (and both the costs of debt and equity) of the order of 70bp would be expected.

In the ICAPM adopted by Brennan and Xia (2006), hereafter the 'BX framework', higher duration increases not only the sensitivity of the asset value to changes in interest rates, but also the sensitivity to the Sharpe ratio.[17] As duration increases, for some assets the greater sensitivity to changes in the risk-free rate (the term premium effect) may be offset by the greater sensitivity to changes in the Sharpe ratio. As a result, although in the BX framework

[13] Deutsche Bank (2012), 'LT Asset Return Study, A Journey into the Unknown', September, p. 46. The ERP estimates in this study are derived by subtracting the 10-year government bond yield from the inverse of the price–earnings ratio.
[14] Europe Economics ((2010), 'The Weighted Average Cost of Capital for Ofgem's Future Price Control—Final Phase 1 Report', December.
[15] Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity', prepared for the Energy Networks Association, June 9th.
[16] Dimson, E., Marsh, P. and Staunton, M. (2012), 'Credit Suisse Global Investment Returns Sourcebook 2012', February.
[17] Brennan, M. and Xia, Y. (2006), 'Risk and Valuation under an Intertemporal Capital Asset Pricing Model', *Journal of Business*, **79**:1.

the security beta increases with duration, the instantaneous expected return may increase or decrease.[18]

Brennan and Xia state that expected returns are more likely to increase with duration for assets where the systematic risk of the cash flows (the cash-flow beta) is lower. In particular, the BX framework implies that expected excess returns increase with duration for cash-flow betas of less than 0.5.

For regulated energy networks, cash flows in any given year would be expected to be relatively insensitive to returns on the market portfolio in that year. Moreover, Oxera conducted empirical analysis of UK companies, which indicated that cash-flow betas for National Grid and Scottish and Southern Energy are comfortably in the range where expected excess returns will increase with duration.[19]

The analysis provided by Oxera adds to a substantial body of empirical evidence in the existing academic literature. When considered against the narrow body of evidence presented by Ofgem's advisers based on a very small number of data points, it is difficult to see why this evidence is given greater weight by Ofgem. There remain strong grounds to believe that an increase in the duration of cash flows for regulated energy networks will lead to a material increase in the cost of capital.

2.4.2 Overall framework

As explained in Oxera's September report in detail, assessing business risk is most transparent and reliable when undertaken at the level of the asset beta. A change in business risk may translate into a change in asset beta and the weighted average cost of capital (WACC)—ie, a change in the costs of both debt and equity. Any changes in business risk need to be translated into changes in the asset beta. The gearing ratio can also be adjusted to reflect changes in business risk, but this is of secondary importance and reflects a transfer of risk between debt and equity.

Therefore, it is recommended that the assumptions around the underlying asset beta are made more transparent in the strategy decision.

[18] Ibid., p. 18.

[19] Oxera (2011), 'The impact of longer asset lives on the cost of equity: estimating cash flow betas', prepared for the Energy Networks Association, July.

3 Cost of debt

The strategy consultation proposes that the allowance for the cost of debt will be updated annually based on movements in the simple ten-year trailing average of Ofgem's chosen measure for the market cost of debt. Ofgem proposes to keep the practical calculation of the allowance the same as is currently proposed for RIIO-T1/GD1.[20]

To ensure that efficient debt costs are recoverable in RIIO-ED1, it is important to analyse the impact of Ofgem's debt indexation proposals on risk and financeability taking into account the specific characteristics of the electricity distribution sector.

The strategy consultation carries over the same debt indexation assumptions from RIIO-T1/GD1 to RIIO-ED1 without providing any DNO-specific analysis. In addition, as outlined in Oxera's September report, a number of issues with the approach used in RIIO-T1/GD1 remain outstanding and are just as valid in the context of RIIO-ED1.

A review of the arguments put forward in the strategy consultation to address some of these issues suggests that there are still a number of shortcomings with the proposed approach for remunerating debt costs. It is recommended that these issues be given further consideration ahead of the RIIO-ED1 strategy decision.

- **Compensation for residual cost of debt risk**. The principle behind debt indexation is to reduce the risk of error in the estimate of the cost of debt, and hence reduce the need to provide a margin ('headroom') in the cost of debt allowance by setting it above the central estimate of the efficient cost of debt, inclusive of debt issuance costs. Ofgem proposes to remove this margin completely under indexation, notwithstanding the fact that the risk of error will not reduce to zero, and in some cases will not reduce materially compared with a fixed cost of debt allowance.
  - All companies will be exposed to risk due both to intra-year volatility in yields and to a time-varying inflation risk premium.
  - For an average DNO, debt indexation leads to only a modest reduction in risk compared with a fixed cost of debt allowance, since only a small proportion of the existing debt needs refinancing in RIIO-ED1. For a number of companies with very low refinancing needs, debt indexation may actually increase risk.
- **Risk of under-recovery of efficiently incurred debt costs**. Given the historical downward trend in the cost of debt and current low levels of yields, there is a material risk of under-recovery of efficiently incurred debt costs in RIIO-ED1. While the risk of divergence between the existing and allowed costs of debt is present in all price controls, in previous price controls companies were compensated for this risk of divergence through a margin in the allowed cost of debt. In addition, the proposed design of the index, combined with current market environment, leads to a higher probability of under-recovery than in previous price controls.
- **Allowance for debt issuance costs**. To ensure that efficient debt costs, including debt issuance costs, are recoverable regardless of the market conditions or other unforeseen circumstances (such as the impact of Solvency II and changes in the index

[20] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.21.

composition), a separate allowance for debt issuance costs would be more appropriate than the current proposals.

Ofgem's duty to allow companies to finance their functions suggests that the above factors cannot be disregarded. It is important that the debt indexation proposals appropriately reflect the risk of error between the allowed and actual cost of debt, and provide adequate protection against under-recovery of efficiently incurred debt costs, inclusive of debt issuance costs. This can be achieved either by providing a suitable margin in the allowed return (on either debt or equity) or, where appropriate, by modifying the debt index or supplementing it with a mechanism to avoid undue exposure to risk.

3.1 Impact on risk

As in RIIO-T1/GD1, Ofgem suggests that debt indexation ensures that efficient debt costs will be recoverable. This therefore removes the need to set the cost of debt allowance above the central estimate of the efficient cost of debt (ie, it removes the need for headroom).[21]

> Setting the cost of debt component of the allowed return in such a way should provide comfort to the DNOs and their investors that efficiently incurred new debt – even at levels higher than the cost of debt assumption at the time – will be fully funded in the future. For consumers, this approach provides assurance that they will only pay for efficient debt costs, and that no "headroom" would be built into the price control package.

The conclusion that the margin (headroom) in the cost of debt allowance can be completely removed is appropriate only if companies no longer bear cost of debt risk under debt indexation—ie, the indexed allowance is a perfect match for the average efficient cost of debt of a typical network in all scenarios. However, for a typical company, debt indexation will not result in a perfect match between the allowance and its efficiently incurred cost of debt. Ofgem and its advisers acknowledged this as part of the RIIO-T1/GD1 review.[22]

In the RIIO-T1/GD1 Initial Proposals Ofgem noted several factors that influence the extent to which the indexed allowance reflects the actual cost of debt of a typical energy network. These factors include the timing and frequency of debt issuance, the coupon on the bonds relative to the market cost of debt, average maturity, and the credit rating.[23] Most of these factors are largely outside a company's control as they reflect the company's CAPEX needs, size, nature of the assets and conditions in the capital markets. The differences between the indexed allowance and actual debt costs would not be expected to be eliminated over time. It is therefore not clear why a move to debt indexation eliminates the need for any compensation for bearing residual cost of debt risk.

A number of industry-wide and company-specific factors will affect how exposure to residual cost of debt risk changes under indexation compared with a fixed cost of debt allowance. To fully understand the implications of debt indexation on risk requires a more in-depth analysis of a typical DNO debt profile.

3.1.1 Industry-wide factors

First, as no company issues debt on a frequent and uniform basis, all companies are exposed to the risk that their issuance yields differ from the average of daily yields that goes into Ofgem's calculation of the ten-year trailing average.

[21] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.10.

[22] FTI Consulting (2012), 'Cost of capital study for the RIIO-T1and GD1 price controls', July 24th, para 8.27.

[23] Ofgem (2012), 'RIIO-T1: Initial Proposals for National Grid Electricity Transmission plc and National Grid gas plc', finance supporting document, July 27th, p. 21; and Ofgem (2012), 'RIIO-GD1: Initial Proposals', finance and uncertainty supporting document, July 27th, p. 19.

The cost of debt allowance is effectively set based on the ten-year average of annual averages of daily yields. On any particular day of the year, the value of the index can exceed the annual average of yields for that year. Assuming no outperformance relative to the market cost of debt, even if companies issue debt more frequently than once a year, there is still a reasonable likelihood that the average cost of new debt issued in that year exceeds the annual average.

If the historical level of intra-year volatility in yields persists or increases,[24] all companies will still have significant exposure to the risk that their actual cost of debt deviates from the regulatory allowance. Previous Oxera analysis has shown that this factor alone leaves a typical company with a residual cost of debt risk of 30% compared with a fixed cost of debt allowance.[25]

Second, as no company issues all debt in an inflation-linked form, all companies have to issue some proportion of their debt in nominal form. Companies compensate their nominal bond investors by paying a yield that includes the real yield, expected inflation, and the inflation risk premium. Ofgem's debt index calculates a real cost of debt by subtracting an estimate of UK break-even inflation from nominal corporate bond yields.[26] As this estimate of break-even inflation will also include any inflation risk premium, this approach will not remunerate companies for the inflation risk premium due to nominal bond investors.

In the strategy consultation Ofgem suggests that 'the inflation risk premium is countered by other factors of a similar magnitude, such as a liquidity premium on index-linked gilts',[27] and that consequently no adjustments to the index are required.

Ofgem's advisers reviewed the recent evidence on the inflation risk premium (that acts to increase yields on nominal bonds relative to equivalent inflation-linked bonds) and also the liquidity risk premium (that acts to increase yields on inflation-linked bonds relative to equivalent nominal bonds). This evidence suggests that it is far from clear that the two would offset each other.

> We find that there is enough evidence to presume the existence of an inflation risk premium and the possible existence of a liquidity risk premium. These premia will both impact Ofgem's calculated inflation estimate but with one offsetting (to a greater or lesser extent) the other's effect. The net effect of the two premia is unclear. Although it seems likely that the inflation risk premium is larger than the liquidity premium.[28]

Importantly, the relative sizes of the inflation and liquidity risk premia are likely to change over time. Companies are therefore exposed to the risk that the inflation risk premium is unusually large on the dates when the company issues debt, and that the debt index will not remunerate companies for an efficiently incurred component of their nominal debt costs.

It is important that the allowed returns for all companies appropriately reflect the risk due both to intra-year volatility in yields and to a time-varying inflation risk premium.

3.1.2 Company-specific factors

The change in exposure to residual cost of debt risk under debt indexation will vary by company depending on the refinancing profile and projected RAV growth for each individual DNO.

[24] See Figure 2.2.

[25] Oxera (2012), op. cit., p. 21.

[26] The estimate of break-even inflation is derived from applying the Fisher relationship to nominal and inflation-linked government bond yields. The Fisher equation links nominal and inflation-linked yields in the following way: (1+nominal yield)=(1+inflation-linked yield)*(1+break-even inflation rate)

[27] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.27.

[28] FTI Consulting (2012), op. cit., para 11.23.

Previous Oxera analysis has shown that, assuming that RIIO-ED1 industry RAV growth is broadly similar to DPCR5, on average for the industry, debt indexation leads to a modest reduction (of around 20%) in the residual exposure to cost of debt risk compared with a fixed allowance. This is largely explained by the fact that only a relatively small proportion of existing debt needs refinancing in RIIO-ED1 (24%).[29] In fact, six of the 14 DNOs will not need to refinance any of their existing debt in RIIO-ED1,[30] which means that debt indexation is likely to increase rather than reduce their exposure to cost of debt risk. This is because their actual costs of debt will be largely fixed for the duration of the price control period while they will be exposed to a time-varying cost of debt allowance, increasing the uncertainty around the difference between the actual and the allowed costs of debt.

Network companies raise debt on terms that are largely driven by the state of capital markets at the time, and in the past have typically raised long-term debt to reflect the nature of their assets. Therefore, it would seem that there is no strong evidence that existing financing profiles are inefficient, and so it would be inappropriate to remove compensation for the risk of error between the allowance and the average efficiently incurred cost of debt.

3.1.3 Summary

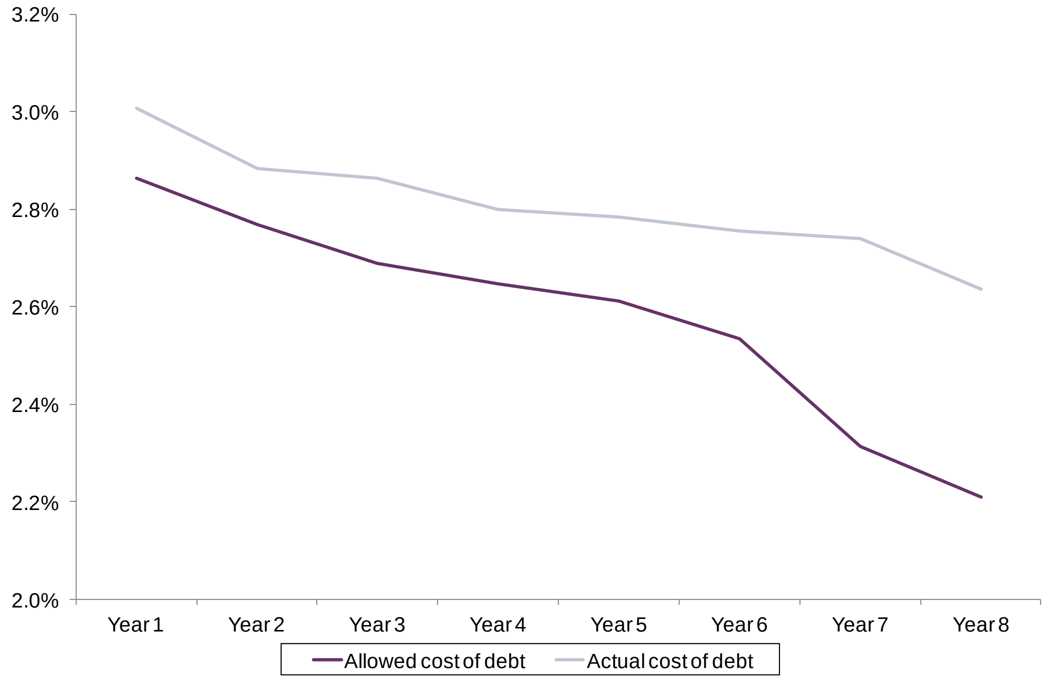
A number of factors suggest that exposure to cost of debt risk will not be zero under indexation. Debt indexation may actually increase the exposure to cost of debt risk compared with a fixed cost of debt allowance. For example, for companies whose debt costs are largely fixed over the price control period, annual updating of the cost of debt allowance will introduce additional uncertainty around the difference between the allowed and the actual cost of debt. It may be necessary to consider mechanisms to modify or supplement the debt index to ensure that companies can finance their functions, with residual uncertainty on the cost of debt being compensated through the allowed return.

3.2 Impact on financeability

Given the recent low levels of yields there is a risk that the ten-year trailing average falls below the efficient cost of debt for a typical network over the RIIO-ED1 period. As part of the RIIO-T1/GD1 reviews, Ofgem's advisers have noted that, with interest rates currently at historically lows, there is a risk that '[d]epending on the future pattern of interest rates, the inclusion of these rates in the index may, therefore, not reflect the efficient costs of debt for a network company over the 2013/21 Price Controls.'[31] Figure 3.1 shows that this risk is just as material in RIIO-ED1 as it is in RIIO-T1/GD1.

[29] Based on data from Dealogic on bonds issued by DNOs on a stand-alone basis.
[30] Ibid.
[31] FTI Consulting (2012), op. cit., para 2.23(4).

Figure 3.1 Expected DNO cost of debt versus the allowance



Note: The allowed cost of debt is estimated assuming that the annual average yield that goes into Ofgem's index remains unchanged from current levels throughout the price control period. The actual cost of debt is based on the assumptions that 24% of existing debt will need refinancing in RIIO-ED1 and that there is real annual RAV growth of 3.1%. The modelling framework is identical to that described in Oxera (2012), 'Determining efficient financing costs for RIIO-ED1', prepared for the Energy Networks Association, September 3rd, Appendix A1. Source: Dealogic, Oxera.

As noted by Ofgem,[32] it is the case that the potential for divergence between existing and new debt costs exists in all price controls. However, in previous price controls, companies were compensated for the risk of divergence through a margin in the allowed cost of debt; and, in the current environment, there is a large probability that the allowed cost of debt will trend downwards for most of the eight-year price control period, increasing the risk of under-recovery.

It should also be noted that Figure 3.1 takes into account the typical refinancing profile of a DNO's existing debt only, and not any other company specific factors. For example, if companies have raised debt in the past at rates higher than the annual average of historical yields that goes into Ofgem's calculation, the potential gap between the actual and the allowed costs of debt could be even wider.

Given the current interest rate environment, it could be suggested that an appropriate financing strategy could be to refinance existing more expensive debt at lower rates. However, such refinancing would come at a cost as it would require existing bonds to be bought back at values above the par value of the bond.[33]

To reduce risk and mitigate the negative impact on financeability, it is recommended that the suitability of the proposed index is reviewed by analysing DNO-specific debt profiles under a range of scenarios. If there is a risk of under-recovery of efficiently incurred debt costs, options to modify or supplement the debt index could be considered.

[32] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.20.
[33] Bonds with higher coupons than the market yields trade at a premium to the par value.

3.3 Debt issuance costs

The proposed allowance for the cost of debt does not explicitly include an allowance for debt issuance costs, on the premise that 'the level of outperformance relative to the index is sufficient to cover any auxiliary costs the DNOs might incur when issuing new debt'.[34] However, Ofgem also notes that recent bond issuances point to a narrowing of the gap between the index and energy network bond issuance yields.[35]

Previous analysis by Oxera has demonstrated that, on average, the DNOs have issued bonds at rates that were closer to the index than other energy networks, and that the gap has indeed narrowed recently.[36]

Regulatory change, such as Solvency II, is one factor that could contribute to the erosion of the gap going forward. As noted by Ofgem's advisers, there is a risk that there might be reduced demand for longer-dated utilities bonds as a result of Solvency II.[37] One potential impact of reduced demand is that it could it make difficult to issue debt below the index.

In addition, as shown in Oxera's September report, changes in the composition of the iBoxx index over time could affect the ability of the energy networks to issue debt below the index.[38] An increase in the weight of utilities in the index over time could mean that issuing bonds at yields below the index would be more difficult going forward.

It would therefore seem appropriate to take a more explicit approach to ensuring that efficient debt costs, including debt issuance costs, are recoverable regardless of the market conditions. A separate allowance for debt issuance costs would be a suitable means of achieving this.

[34] Ofgem (2012), 'Consultation on strategy for the next electricity distribution price controls—RIIO-ED1—Financial Issues', September 27th, para 2.15.

[35] Ibid., para 2.18.

[36] Oxera (2012), op. cit., pp. 21–2.

[37] FTI Consulting (2012), op. cit., para 9.20.

[38] Oxera (2012), op. cit., pp. 22–3.

Park Central
40/41 Park End Street
Oxford OX1 1JD
United Kingdom

Tel: +44 (0) 1865 253 000
Fax: +44 (0) 1865 251 172

Stephanie Square Centre
Avenue Louise 65, Box 11
1050 Brussels
Belgium

Tel: +32 (0) 2 535 7878
Fax: +32 (0) 2 535 7770

200 Aldersgate
14th Floor
London EC1A 4HD
United Kingdom

Tel: +44 (0) 20 7776 6600
Fax: +44 (0) 20 7776 6601

www.oxera.com

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RIIO-ED1 risk assessment framework

Note prepared for Energy Networks Association

April 10th 2013

1 Executive summary

Oxera has been working with the Energy Networks Association on developing a comparative risk assessment framework for the next electricity distribution price control (RIIO-ED1).

The risk assessment framework presented in this note is intended to be used as a tool to assess the potential changes in asset risk in RIIO-ED1 relative to the last price control (DPCR5) and also to enable comparisons with other recent RIIO price control decisions for the transmission and gas distribution companies (RIIO-T1 and GD1 respectively) in a consistent manner.

Asset risk can be defined as the volatility of the return on assets. Asset risk relates to operational, rather than financial, drivers of a company's performance—ie, it is not affected by capital structure, and hence it is typically considered to be the most appropriate measure of business risk to be used as a basis for cost of capital estimation.

The framework presented in this note suggests that, broadly, the key risk factors affecting the change in asset risk in RIIO-ED1 can be categorised by consideration of two questions.

– Is the direction of change in asset risk in RIIO-ED1 from a given risk factor already reasonably clear at this stage of the process?

– Can the change in asset risk from this risk factor be quantified robustly?

Tables 1.1 and 1.2 below summarise the key risk drivers analysed, their relationship with asset risk, and, where possible, quantify the impact on the change in asset risk for RIIO-ED1.

The assessment suggests that, at an industry level, relative to DPCR5, the impact of quantifiable risk drivers where the direction of change is already known is not trivial and is positive, ie, asset risk is expected to be higher in RIIO-ED1. The increase in asset risk is estimated to be in the range of 5–20%. This increase in risk can be translated into:

– an equity beta range of ~0.95–1.20 at 65% gearing; or, equivalently,
– an equity beta range of ~0.90–1.10 at 60% gearing.

This compares with Ofgem's proposed range of 0.90–0.95 (without a specified gearing level). These ranges exclude the effect of the other risk drivers, where the direction of change is not yet known, or where the impact cannot be quantified. Some of the excluded factors such as the efficiency incentive rate and pension cost risk may be expected to increase risk further. It may be possible and more appropriate to reflect the impact of some of these additional factors in the notional gearing assumption.

A comparison with RIIO-T1 and GD1, using the same framework, suggests that RIIO-ED1 could be closest in risk exposure to NGET within the RIIO-T1 price control, and is likely to be riskier than the RIIO-GD1 control. The comparison across sectors has not considered the differences in asset risk that may arise due to differences in the nature of TOTEX and uncertainty mechanisms since these differences would be expected to be largely influenced by technical factors.

The combination of the cost of equity and notional gearing assumptions for RIIO-ED1 needs to reflect appropriately the changes in asset risk since DPCR5 and the relative comparison with RIIO-T1 and GD1.

Table 1.1 Change in asset risk in RIIO-ED1 compared with DPCR5

Risk factor	Relationship with asset risk	Change in asset risk
Scale of TOTEX	A higher ratio of costs to asset value increases potential deviation of average return on assets from forecast; total cash costs (ie, TOTEX) are what is important for determining asset risk; change in risk depends on unexpected changes in long-term expected ratio of costs to asset value	—
Nature of TOTEX	Changes in the nature of TOTEX could affect cost volatility, and, subsequently, asset risk; if forecasting TOTEX in RIIO-ED1 is more challenging (eg, due to uncertainty around the take-up of low-carbon technologies), this would increase potential deviation of costs from forecast	✓
Length of the price control	A longer price control increases potential deviation of average return on assets from forecast; timing of revenue adjustments and having fewer regulatory resets does not fully mitigate the increase in risk	5–15%
Efficiency incentive rate	A higher efficiency incentive rate increases potential deviation of average return on assets from forecast	Depends on company plans ~0.5–1% increase for every 1% proportionate increase[1]
Uncertainty mechanisms	Most mechanisms are similar to DPCR5; new mechanisms address new risks not present at DPCR5; some mechanisms are being removed	—
Cash-flow duration	Increase in regulatory asset lives increases the required rate of return	Up to ~5%[2]
Regulatory incentives	Some incentives are being removed (eg, losses incentives), while others are being introduced or strengthened. Total return exposure proposed to remain largely similar	—
Pensions	Transitioning fully to RIIO pension principles	✓✓
Total	**Asset risk is expected to go up**	**Total increase is in the range of 5–20%[3]**

Note: —, no material change; ✓, change is uncertain but likely to be positive; ✓✓, positive change but cannot be quantified. [1] The comparison should also take into account the change from a pre-tax to a post-tax application of the incentive rate. [2] The upper bound of 5% is before the effect of any transitional arrangements applied to new assets. [3] The range includes the impact of quantifiable factors only, and is before taking into account any changes in the efficiency incentive rate. The change in asset risk reflects the increase in the asset risk premium (difference between vanilla WACC and the risk-free rate) since DPCR5. Since the cost of debt in RIIO-ED1 will be indexed to a generic bond index, the increase in asset risk needs to be fully reflected in the equity beta. For more details, see Oxera (2012), 'Determining efficient financing costs for RIIO-ED1', September, Table 2.2.
Source: Oxera.

Table 2.1 Asset risk in RIIO-ED1 compared with RIIO-T1 and GD1

Risk factor	Comparison with RIIO-T1	RIIO-ED1 asset risk relative to RIIO-T1	Comparison with RIIO-GD1	RIIO-ED1 asset risk relative to RIIO-GD1
Scale of TOTEX	Could be closest in the risk exposure to NGET, assuming similar nature of TOTEX	Varies by transmission operator	Could be higher risk than the GDNs, assuming similar nature of TOTEX	✓✓
Length of the price control	Could be slightly higher due to different licence disapplication conditions	✓	Could be slightly higher due to different licence disapplication conditions	✓
Efficiency incentive rate	Depends on company plans: lower end of RIIO-ED1 proposed range comparable to T1 numbers	—	Depends on company plans: upper end of ED1 proposed range comparable to GD1 numbers	—
Uncertainty mechanisms	Not directly comparable	n/a	Not directly comparable	n/a
Regulatory incentives	Cash-flow volatility could be higher	✓	Cash-flow volatility could be higher	✓
Pensions	Higher	✓✓	Higher	✓✓
Total	**Could be closest in risk exposure to NGET, assuming similar nature of TOTEX**	**Varies by transmission operator**	**Likely to be higher risk than the GDNs, assuming similar nature of TOTEX**	✓✓

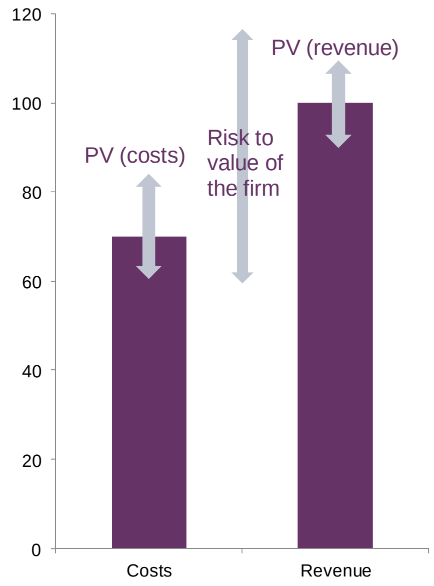
Note: —, unclear at this stage; ✓, uncertain but likely to be higher risk; ✓✓, likely to be higher risk but cannot be quantified. GDN, gas distribution network.
Source: Oxera.

2 Scale and nature of TOTEX

The value of the firm is simply the difference between the present value (PV) of revenues and costs.[1] This means that asset risk—defined as the volatility of the return on assets—is a function of both revenue and cost risk, and that the relative contribution of revenue and cost risk to total asset risk depends on the ratio of PV of revenues and costs to PV of assets respectively (Figure 2.1).

[1] Allen, F., Myers, S. and Brealey, R. (2008), *Principles of corporate finance*, McGraw-Hill, International Edition, Chapter 10.

Figure 2.1 Illustration of the relationship between revenue, costs and asset value



Source: Oxera.

In other words, there is a direct relationship between the proportion of costs to asset value and asset risk.

– A higher proportion of costs relative to asset value increases operational 'beta' leverage—ie, for any given change in PV of costs, the proportionate impact on the PV of assets is greater if the ratio of costs to asset value is bigger. This means that cost volatility has a greater impact on the volatility of asset returns for a company with a bigger ratio of costs to asset value, thus increasing asset risk and the asset beta (assuming some of the cost volatility is systematic).

– Since it is total cash costs that affect the relative PV of costs to PV of assets, this means that both CAPEX and OPEX matter.

– What matters for the rate of return on assets required by investors is the long-term expected ratio of PV of costs to PV of assets. The relationship between the long-term expected ratio of costs to asset value and asset risk is approximately linear.

– In a regulated setting, unless there are significant unexpected changes in the long-term ratio of costs to asset value, asset risk would not be expected to change materially between different price control periods.

Using the average TOTEX/RAV ratio over the price control period as a proxy for the long-term ratio of costs to asset value and the initial projections available for RIIO-ED1, the following observations can be made (Table 2.1).

– There is no evidence of a significant and unexpected step change in the long-term ratio of costs to asset value in the electricity distribution sector over time.

– On the scale of TOTEX factor alone, the electricity distribution sector in RIIO-ED1 appears to be similar risk to NGET, lower risk than SHETL and SPTL, and higher risk than the gas distribution networks (GDNs) and NGGT.

Table 2.1 Average TOTEX/RAV ratios over the price control period

	DPCR4	DCPR5	RIIO-ED1	RIIO-T1[1]				RIIO-GD1
				NGET	NGGT	SHETL	SPTL	
TOTEX/RAV (%)	15	16	16	16	11	35	23	12

Note: RIIO-ED1 projections are based on TOTEX estimates produced as part of the Cost Assessment Working Group in September 2012 and forecast closing RAV values for the end of the current regulatory period (DPCR5). Source: Ofgem (2004), 'Electricity Distribution Price Control Review Final Proposals', November; Ofgem (2009),'Electricity Distribution Price Control Review Final Proposals', December; Ofgem (2012), 'RIIO-T1: Final Proposals for SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd', April; Ofgem (2012), 'RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas', December; Ofgem (2012), 'Cost Assessment Working Group', Meeting 7, September 18th. [1] For transmission companies, TOTEX is based on Ofgem's best view.

Nature of TOTEX

This comparison does not take into account the differences in the nature of OPEX and CAPEX between the different sectors (and the relative split of TOTEX between ex ante allowances and uncertainty mechanisms) as well as any changes to the nature of either OPEX or CAPEX across time within a given sector.

Put differently, the framework and analysis described above assumes that cost volatility remains constant across time. However, if there is evidence that cost volatility is changing in RIIO-ED1 relative to DPCR5, this could also affect asset risk, and would need to be factored into the risk assessment separately.

3 Length of the price control

Intuitively, a longer price control would be expected to increase cost risk because it is more likely that outturn costs will differ from regulatory allowances if the allowances have to be set for a longer time period. Although the average expected return on assets stays the same, the dispersion (standard deviation) around the mean would be expected to increase.

If cost risk increases, this would increase total risk, which in turn would be expected to increase systematic risk (asset beta). Unless all of the increase in risk relates to non-systematic (diversifiable) risk, an increase in total risk would imply an increase in systematic risk. A reasonable assumption is that the proportion of systematic risk to total risk would remain unchanged, which means that any change in asset risk can be directly translated into a change in systematic risk.

For the hypothesis that a longer price control increases asset risk not to hold, the following conditions would be expected to be met.

– None of the cost shocks carry over into the following years—ie, the level of costs in a particular year is completely independent of the level of costs in the previous year (following a cost shock in one year of the price control, costs fully mean revert to the forecast level in the following year). In this case, it is possible that extending the length of the price control does not increase the volatility of the return on assets.

– The increase in asset risk from a longer price control is fully offset by additional risk-sharing mechanisms in the regulatory framework.

Oxera has developed a stylised model to test the above propositions. The assumptions and the workings of the model have been developed following a number of interactions with Ofgem and the industry. The model estimates the difference in the volatility of the internal rate of return (IRR) between a five- and an eight-year price control under a range of different assumptions and scenarios.

The modelling shows that—as intuitively expected—the degree of autocorrelation in costs is the key driver of the difference in risk between a five- and an eight-year price control (Table 3.1). In simple terms, the autocorrelation coefficient describes what proportion of any deviation of outturn costs from forecast in one year carries over into the following year. If there is at least some positive autocorrelation, Table 3.1 shows that an eight-year price control is riskier than a five-year price control. In the extreme scenario, which assumes that costs display zero autocorrelation, the risk of a five- and an eight-year price control is approximately the same.

Table 3.1 Change in asset risk

Autocorrelation coefficient	Standard deviation of IRR with five-year price control	Standard deviation of IRR with eight-year price control	Increase in risk from moving from five- to eight-year price control
0.0	0.05%	0.05%	2%
0.1	0.05%	0.06%	4%
0.2	0.06%	0.06%	7%
0.3	0.06%	0.07%	11%
0.4	0.07%	0.08%	15%
0.5	0.07%	0.09%	20%

Note: The model covers a 40-year period to ensure the IRR is measured over the same time period regardless of the length of the price control and includes a discrete number of full price control periods. The absolute value of the standard deviation of IRR produced by the model is quite small; this is largely a result of the IRR being measured over a 40-year period. The standard deviation of IRR measured over a single price control period is larger.
Source: Oxera.

Based on the results above, it seems plausible that the increase in risk from a longer price control could be of an order of magnitude of 10–20%. This range is based on an assumption that around 30–50% of any cost deviations carry forward into the following year, which seems reasonable. An autocorrelation coefficient of zero would be a very strong assumption to make.[2]

Further, the modelling tests the sensitivity of the results to a number of assumptions, taking into account the suggestions made to Oxera by Ofgem, specifically the following.

– **Timing of revenue adjustments**. Under the TOTEX incentive mechanism, the company recovers (shares) a proportion of cost under- (out-) performance with customers. Prior to RIIO-ED1, the revenue adjustment was carried out at the start of the next regulatory period. In RIIO-ED1, the adjustment will be carried out annually (with a two-year lag). Both adjustments are performed on an NPV-neutral basis. The model allows either type of adjustment to be applied. If the adjustment is done at the start of the next regulatory period with a five-year price control, and annually with an eight-year price control, then the increase in risk is partially mitigated by having annual adjustments in the eight-year price control. The range for the increase in risk is reduced to about 5–15% (based on an autocorrelation coefficient of 0.3–0.5). However, the change in risk remains positive, assuming some autocorrelation in costs.

[2] Appendix 1 shows the historic trends in key input prices affecting the DNOs. The cost trends indicate that the gaps between RPI and input price indices are not constant over time, and show some persistence over time.

– **Underlying trend in costs**. The model allows for different trajectories of the forecast level of costs to be modelled: constant (in real terms), upward trend, downward trend, or cyclical. The choice of the cost trajectory does not have a material impact on the change in risk shown in Table 3.1.

– **Reset of regulatory cost allowances**. The model allows for different methods to reset cost allowances at the start of each price control period that place different weights on the actual cost levels in the previous control period. The choice of the reset method does not have a material impact on the change in risk shown in Table 3.1.

– **Uncertainty around regulatory reset**. The model also allows for inclusion of some uncertainty around the regulatory cost allowances by introducing a random error into regulatory forecasts. This sensitivity was added to reflect the possibility of 'regulatory reset risk'. Introducing regulatory reset risk does appear to have some impact on the increase in risk from a longer price control; however, it does not necessarily act to reduce the increase in risk in all scenarios. Intuitively, it is not clear that having fewer regulatory resets should mitigate the increase in risk from a longer price control. On the one hand, with a longer price control the regulated company is exposed to fewer 'errors' in regulatory cost allowances which may reduce risk. On the other hand, with a longer price control the regulated company is exposed to the 'regulatory error' for longer which may increase risk. Which of the two effects is stronger appears to vary depending on the other modelling assumptions.

Overall, the analysis suggests that in most plausible scenarios asset risk is expected to go up from a longer price control, and the impact is non-trivial. A plausible range for the increase in risk could be around 5–15%, after taking into account the timing of revenue adjustments proposed for RIIO-ED1.

It is noted that this assessment does not fully align with the Moody's assessment of the impact of the length of the price control.

> A key change introduced for RIIO-GD1 is an extension of the price control period from five to eight years. However, we consider this change to be credit neutral overall. On the one hand, while there is the potential for companies having to wait longer for prices to be reset if specific costs increase, this risk is largely mitigated by the number of uncertainty mechanisms (such as true-ups and the move to a cost of debt index) included within the package.[3]

However, Moody's has not presented detailed analysis of this factor. Moreover, its assessment focuses on credit risk, and while the finding of higher asset risk under a longer price control does not necessarily translate directly into a potential downgrade for the networks, the higher asset risk still implies a higher cost of equity. Finally, its assessment is for RIIO-GD1 only, and so may not be directly applicable to RIIO-ED1, especially considering that the package of uncertainty mechanisms and the nature of TOTEX in RIIO-ED1 is likely to be different (eg, due to exposure to low-carbon connections) to RIIO-GD1.

The impact of uncertainty mechanisms, other than the TOTEX incentive mechanism, has not been explicitly modelled; however, the discussion in section 4 suggests that there is no clear evidence that other uncertainty mechanisms would be expected to mitigate the risk of a longer price control.

[3] Moody's (2013), 'Special Comment: UK Gas Distribution Networks: Transition to RIIO is Credit Neutral', March 8th, p. 4.

In addition, while there may be some scope for management action to make offsetting cost savings, the scope for such action is expected to be limited for an industry that has achieved significant cost reductions since privatisation. It is also possible to reflect some degree of management response in the choice of the cost autocorrelation coefficient.

Finally, compared with RIIO-T1 and GD1, the differences in the price control disapplication clauses between the DNOs and other networks suggest that it may be harder for the DNOs to re-open the price control relative to other energy networks. This emphasises the need to correctly take into account the increase in asset risk from a longer price control in RIIO-ED1.

4 Uncertainty mechanisms

Apart from the TOTEX incentive mechanism, which could be regarded as an uncertainty mechanism that mitigates the exposure to cost risk, the regulatory framework typically includes a number of additional uncertainty mechanisms that are intended to mitigate the impact of some revenue and cost risks. However, uncertainty mechanisms are a feature of both the current regulatory framework in DPCR5 and the proposed RIIO-ED1 framework. Therefore, to assess the change in asset risk between DPCR5 and RIIO-ED1 as a result of uncertainty mechanisms, it is important to assess the incremental changes in the proposed uncertainty mechanisms.

Based on the assessment presented in Table 4.1 below, it is not evident that the scope of uncertainty mechanisms proposed for RIIO-ED1 provides greater protection against risk than the current DPCR5 arrangements. Where new mechanisms have been introduced, these are generally to address new risks that were not present at DPCR5. It is also noted that the low-carbon volume driver originally proposed in the September consultation document will no longer be introduced in RIIO-ED1. This leaves the general load-related reopener as the only mechanism to address the uncertainty around the costs associated with the connection of low-carbon and clean energy devices—to what extent this mechanism is sufficient to address this new and potentially large source of uncertainty is unclear. In addition, some DPCR5 mechanisms are being removed (eg, the annual high-volume low-cost connections driver and the rising and lateral mains reopener).

At best, the assessment suggests that asset risk remains unchanged since DPCR5. Some factors, such as the fact that most of the reopener thresholds are assessed after the application of the efficiency incentive rate which is unlikely to decrease in RIIO-ED1 and in fact may increase, suggest that the risk mitigation offered by some of the mechanisms would be expected to be lower in RIIO-ED1 relative to DPCR5.

Overall, the proposed uncertainty mechanisms do not appear to provide greater risk mitigation relative to DPCR5, and therefore are not expected to mitigate the increase in asset risk resulting from a longer price control.

Table 4.1 Comparison of proposed RIIO-ED1 and DPCR5 mechanisms

Type	Area covered	Frequency of adjustment	Exists in DPCR5	Asset risk reduced relative to DPCR5?
Mechanistic				
Indexation	RPI indexation of revenues	Annual	✓	No, same mechanism
	Cost of debt	Annual	x	Addresses financing, not asset risk. Further, previous analysis has shown that financing risk may actually increase for some DNOs under debt indexation
Pass-through	Business rates	Annual	✓	No, same mechanism
	Ofgem licence fees	Annual	✓	No, same mechanism
	DCC fixed costs	Annual	x	Most likely no. Additional mechanism but addresses new risk largely not present at DPCR5
	Transmission connection point charges	Annual	✓	No, similar mechanism
Volume driver	Smart meter roll-out costs		x	Most likely no. Additional mechanism but addresses new risk largely not present at DPCR5
Assessed				
Reopener	Street works	Single window 2019	✓	No. Same number of re-opener windows and same threshold; subject to efficiency incentive rate, which may be higher in RIIO-ED1
	Enhanced physical site security	Single window 2019	✓	No. Same number of re-opener windows and same threshold; subject to efficiency incentive rate, which may be higher in RIIO-ED1
	High-value projects	Single window 2019	✓	No. Qualifying threshold increased from £15m to £25m; subject to efficiency incentive rate, which may be higher in RIIO-ED1
	Load-related expenditure	2017, 2020	✓	Most likely no. Same materiality threshold; subject to efficiency incentive rate which may be higher in ED1; two re-opener windows and covers more expenditure categories, but this is aimed at addressing new and increased uncertainty associated with connecting low-carbon technologies
	Innovation roll-out mechanism	2017, 2019	x	Most likely no. Additional mechanism but addresses new risk largely not present at DPCR5
	Pension deficit repair mechanism	2016, 2019, 2022	✓	Slightly. Frequency of allowance resets increased from five years (end of DPCR5) to every three years
Trigger	Tax	Any time	✓	No
Overall assessment				**At best, asset risk in RIIO-ED1 is unchanged**

Source: Ofgem (2013), 'Strategy decision for the RIIO-ED1 electricity distribution price control—Uncertainty mechanisms', March 4th.

5 Efficiency incentive rate

A higher efficiency incentive rate exposes the company to a greater share of any cost shock since a smaller proportion of any cost under- (out-) performance is shared with customers. This means that although the average expected return on assets stays the same, the dispersion (standard deviation) around the mean increases. An increase in cost risk, as explained in earlier sections, would increase total risk, which in turn would be expected to increase systematic risk (asset beta).

Intuitively, a 1% proportionate increase in the incentive rate translates into a 1% increase in the cost risk. The change in asset risk depends on the relative contribution of cost and revenue risk to asset risk. For example, if cost risk contributes at least 50% to total risk, the increase in asset risk would be at least 0.5% for every 1% proportionate increase in the incentive rate.[4]

This suggests that material changes in the incentive rate could have a significant impact on asset risk. Ofgem's intended incentive rate range for RIIO-ED1 is 45–65% with a rate of 70% for the fast-tracked DNOs.[5] The incentive rates in DPCR5 are in the 45–50% range.[6] At the very least, this suggests that a decrease in asset risk from a change in the incentive is very unlikely for any of the DNOs.

Furthermore, the incentive rates in RIIO-ED1 will be applied on a post- rather than the pre-tax basis used in DPCR5. This means that, on a like-for-like basis, the same headline incentive rate exposes the networks to greater cost risk in RIIO-ED1 relative to DPCR5. This change in the application of the incentive rate should be taken into account when comparing RIIO-ED1 with DPCR5.

Compared with RIIO-T1 and GD1, the incentive rates in RIIO-T1 (45–50%) are consistent with the lower end of the RIIO-ED1 proposed range, and the incentive rates in RIIO-GD1 (63–64%) are consistent with the upper end of the RIIO-ED1 proposed range. The final comparison with RIIO-T1 and GD1 will depend on individual company plans, but at this stage there is no evidence that RIIO-ED1 will be any less risky than RIIO-T1 and GD1 on the basis of the efficiency incentive rate.

The increase in strength of incentives from DPCR5 to RIIO-ED1 would appear to be consistent with the overarching principle of the RIIO framework. However, if the change in the RIIO-ED1 incentive rate is expected to be material, one option to mitigate the impact of this change on the required rate of return while preserving the strength of incentives might be to adopt a lower notional gearing assumption.

6 Other risk factors

There are also a number of other risk factors that need to be taken into account in the relative risk assessment. They include cash-flow duration, regulatory incentives, and pensions.

[4] For example, an increase in the incentive rate from 50% to 55% is equivalent to a 10% proportionate increase in the incentive rate, and hence a 10% increase in the cost risk. Assuming cost risk contributes at least 50% to total risk, the overall impact on asset risk is an increase of at least 5%.

[5] Ofgem (2013), 'Strategy decision for the RIIO-ED1 electricity distribution price control—Outputs, incentives, and innovation', March 4th.

[6] Ofgem (2009),'Electricity Distribution Price Control Review Final Proposals', December.

6.1 Cash-flow duration

Oxera has previously presented evidence that suggests that the increase in regulatory asset lives in electricity distribution will increase the cost of capital.[7] Following the publication of Ofgem's strategy decision, it remains difficult to see why the narrow body of evidence presented by Ofgem's advisers, based on a very small number of datapoints, is given greater weight by Ofgem than the substantial body of empirical evidence presented by Oxera.

It is recognised that the impact of the change in asset lives on the cost of capital may be mitigated by the fact that the longer asset lives will only apply to new assets and companies will be able to propose transitional arrangements. However, even after taking these factors into account, the fact remains that the impact on the cost of capital is not trivial. For example, based on the historical difference in returns on long-maturity compared to short-maturity bonds, the increase in the cost of capital was previously estimated by Oxera to be around 70bp (if the change were applied to all assets).[8] If real RAV growth is assumed to be zero over the eight-year period, then 40% of assets at the end of the period will be new assets—20% on average. The increase in the cost of capital could then be expected to be of a magnitude of ~15bp (before the application of transitional measures), which is equivalent to around a 5% increase in asset risk.[9]

6.2 Regulatory incentives

Based on the return on regulatory equity (RoRE) analysis produced by Ofgem in the strategy decision, the contribution of regulatory incentives to the potential to earn higher or lower returns in RIIO-ED1 is intended to be higher compared with RIIO-T1 and GD1.[10] This suggests that, all else equal, the DNOs could be exposed to slightly more revenue risk from regulatory incentives compared with RIIO-T1 and GD1 companies.

Relative to DPCR5, the financial exposure on a number of incentives[11] (eg, the Broad Measure of Customer Satisfaction, or BMCS), connections and reliability (eg, the interruption incentive scheme) is increasing. At the same time, some incentives are being removed, such as the losses incentive, which was a relatively important contributor to the width of the RoRE range in DPCR5. Overall, based on the RoRE chart produced by Ofgem in the strategy decision, the RoRE exposure to incentives for a fast-tracked DNO looks to be reasonably similar to DPCR5.

This suggests that there is no evidence that the contribution of regulatory incentives to total risk is decreasing in RIIO-ED1, and there is some evidence that this contribution is higher in electricity distribution compared with other energy networks. While it is unclear to what extent the regulatory incentives contribute to systematic risk, they are expected to affect cash-flow volatility and so may have some impact on the appropriate level of notional gearing.

6.3 Pensions

For RIIO-ED1 Ofgem will rely, with some refinements, on the pension principles that were agreed as part of the DPCR5 price control, the June 2010 Pension document, and the RIIO-

[7] For the most recent summary of key arguments, see Oxera (2012), 'RIIO-ED1 strategy consultation—financial issues', November 12th.

[8] Oxera (2012), op. cit.

[9] The change in asset risk is derived from the expected increase in the cost of capital.

[10] Ofgem (2013), Strategy decision for the RIIO-ED1 electricity distribution price control—Financial issues', March 4th, Figures 3.2 and 3.3.

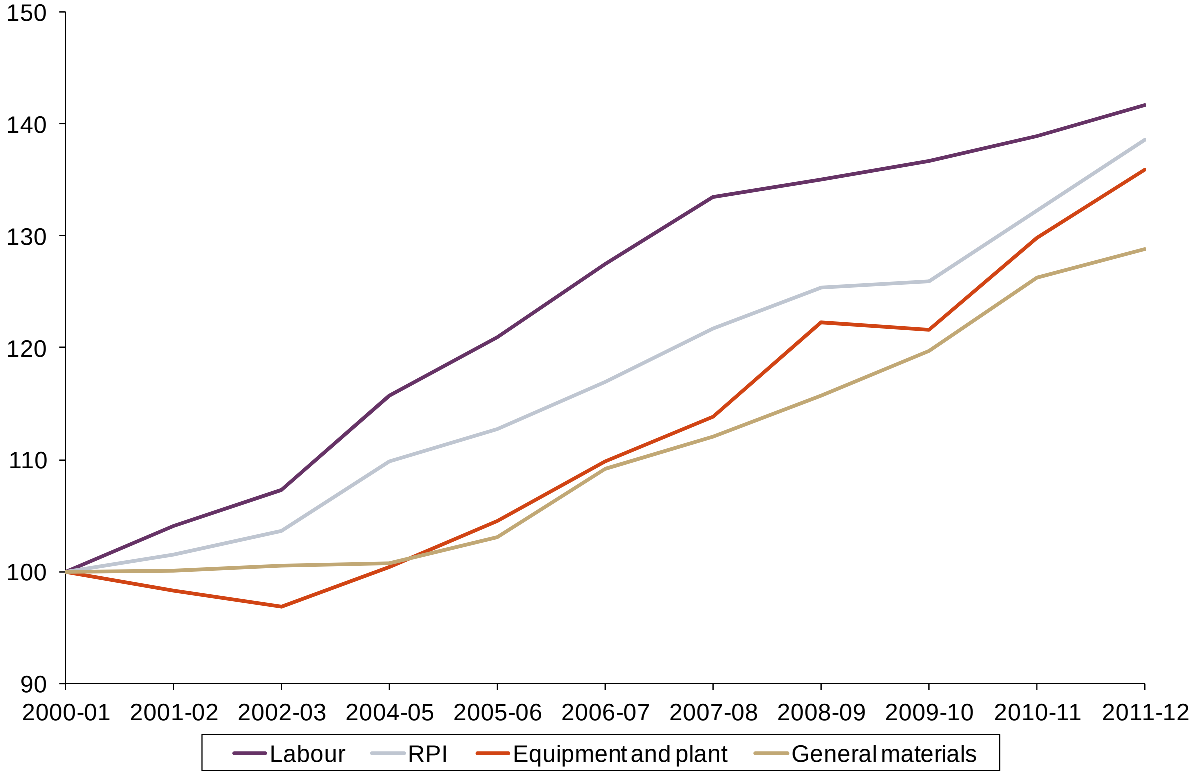
[11] As measured by possible upside and downside basis points of RoRE.

T1 and GD1 controls.[12] For the DNOs, the new pension methodology means that the incremental part of the deficit accrued beyond March 31st 2010 will be subject to an efficiency challenge as part of total employment costs. This compares to the cut-off date of March 31st 2012 for transmission networks and March 31st 2013 for GDNs. This suggests that, compared with RIIO-T1 and GD1, the DNOs are likely to be exposed to higher pension cost risk, and hence higher cost risk.

[12] Ofgem (2010), 'Price control treatment of network operator pension costs under regulatory principles', June 22nd.

Appendix 1

Figure A.1 Evolution of input prices over time



Source: ONS, BCIS, and Oxera. ONS indices shown are Private Sector Average Earnings index (including bonus), Retail Price Index, electrical machinery and apparatus, BCIS building costs materials index for labour, RPI, equipment and plant, and general materials, respectively.