RIIO T1 Business Plan

Section 9 Financial Strategy

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9. FINANCIAL STRATEGY

Contents

9.1 Introduction

In this section we set out our financial strategy for the RIIOT1 period.

We present our base assumptions within 9.2 Financial Inputs. We then present the financial consequences of these assumptions within 9.3 Financial Results – Base Case. We present our detailed consideration of various risks and our proposed management of these within section 9.4 Management of Risk. There follows in 9.5 a detailed assessment methodology including a full RORE analysis which we have undertaken to stress test our base position. Finally we present our evaluation of the financial consequences of this risk assessment upon our financial plan in section 9.6 Financial Results – Including Risks & Incentives.

The separate Appendix 1 entitled "SPT's Cost of Capital – Presentation for Ofgem" should also be read in conjunction with the Financial Inputs section. This is an update to a presentation made to Ofgem earlier this year which underpins much of our empirical evidence. Appendix 2 highlights corrections and amendments we have made to Ofgem's financial model.

We have also submitted Ofgem's financial model containing full detail on our financial strategy.

9.2 Financial Inputs

Introduction

Iberdrola, the ultimate parent of SPTL remains committed to participate in the sizeable investments needed in the UK electricity sector. It is an experienced industry player with the capability to help fulfil the UK agenda in developing smarter networks, meet environmental challenges and to securing energy supplies.

Iberdrola has considerable international reach with a strong track record in regulated activities in Spain, the USA and Brazil as well as the UK and brings direct industry expertise which through planning and operational excellence can add more value than can a purely financial investor.

Given the very large capital expenditure programme presented in this business plan, i.e. an investment proposal of £2.6B (nominal) in our 'best case' across the RIIO-T1 period and consequent more than doubling of the RAV we would urge Ofgem to support our proposal for an adequate return and financeability package such that this investment is not discouraged. Ofgem will be aware that there would be very serious consequences for the UK economy in terms of employment as well as security of supply if funds are attracted to alternative investment opportunities that exist in other regulated or unregulated sectors in the UK or internationally.

We believe that the new RIIO-T1 provides a full 'toolkit' to allow the UK Government, Ofgem and Companies alike to meet their objectives without placing an unfair burden upon customers. We believe we have submitted a fully justified, financeable business plan which delivers investment grade credit ratings.

This is in large part achieved by moving to a ***notional gearing level of 50%*** alongside a sizeable ***equity injection of close to £375M*** during the period. Our plans include an assumed ***cost of equity at the top of Ofgem's recommended range*** to recognise various risks within the overall package, some generic features of RIIO-T1 and some specific to SPTL. We have proposed a ***transitional arrangement*** to mitigate the negative short term cash flow implications of the move to an approximation of useful economic regulatory asset lives.

Summary of Financial Model Assumptions

Model Assumption	Value/ Approach	Bespoke Feature
Cost of Equity	7.2%	n/a
Cost of Debt	Indexation	n/a

Gearing	50%	n/a
Asset Lives	45	New assets only after RIIO-T1 period with interim 'stepped' transition from 20 years to 45.

The key assumptions we have made are explained in further detail below.

Cost of equity

NERA have advised[1] us that the cost of equity for SPT for RIIO-T1 lies within the range of 7.3% to 8.1%. This comprises:

	Long-run	**Current Market**
Market returns	7.2%	9.6%
Risk free rate	2.0%	0.7%
Equity Risk Premium	5.2%	8.9%
Asset beta for Network Operator	0.41	0.32
Gearing	50%	50%
Equity Beta	0.82	0.64
Single period CAPM for average Network Operator	6.3%	6.4%
SPT uplift for capex risk	0.5%	0.5%
Compensation for extended asset lives	0.5%	0.5%
Projected increase in risk free rate		0.7%
SPT Cost of equity	**7.3%**	**8.1%**

[1] Appendix 1: NERA, SPT's Cost of Capital – A presentation for Ofgem, updated 21 February 2011

An earlier version was discussed with Ofgem on 17th February 2011, which was then updated to ensure that the projected increase in the risk free rate was not double counted.

We have cross-checked this against:

- the Dividend Growth Model (DGM);
- historic returns on the overall UK market;
- expected market returns
- returns allowed by FERC for electricity transmission operators; and
- the Inter-temporal Capital Asset Pricing Model

Dividend Growth Model

Using the forward looking DGM, NERA estimate[2] the average cost of equity to be within the range of 7.4 to 7.9% (at 50% gearing).

NERA estimate dividend growth rates based on explicit analysts' forecasts, in the short term, and long run GDP growth expectations for the long term.

US regulators typically use the DGM to calculate the cost of equity.

Historic market returns

As Smithers & Co noted[3], the overall market return is more stable than the individual components of the CAPM.

The arithmetic average total market return is 7.2%, which is calculated from UK data from the Credit Suisse Global Investment Returns Sourcebook 2011.

For TPCR4, Smithers' estimated[4] the implied arithmetic mean for total market returns using a "Taylor Rule" approach:

Arithmetic Total Market Return = Geometric Total Market Return + ½ Equity Market Variance

Updating Smithers' approach with UK data from the Credit Suisse Global Investment Returns Yearbook 2011 gives:

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[2] Appendix 1: NERA, SPT's Cost of Capital – A presentation for Ofgem, slide 33, 21 February 2011

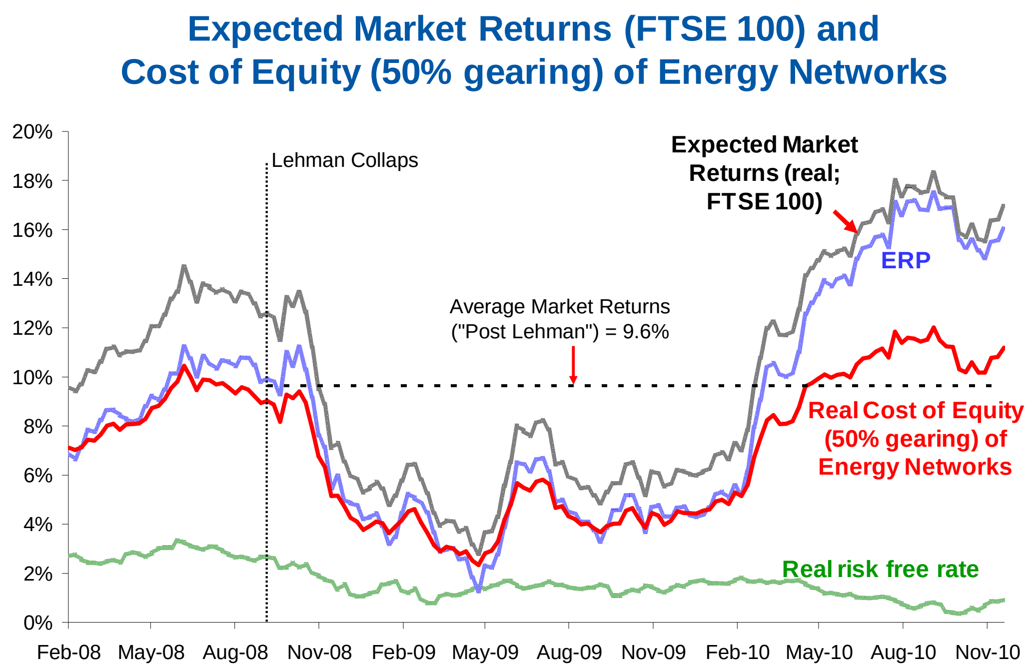
[3] Smithers & Co. Ltd., A Study into Certain Aspects of the Cost of Capital for Regulated Utilities in the U.K., 13 February 2003

[4] Smithers & Co. Ltd., Report on the Cost of Capital – provided to Ofgem, 1 September 2006

A	Geometric Mean returns (1900-2010)	5.3%
B	Standard Deviation of returns (1900-2010)	20%
C	Variance of returns (=B^2)	4.0%
D	½ Variance (=C/2)	2.0%
E	**Implied Arithmetic mean return (=A+D)**	**7.3%**

Expected market returns

Again, using the DGM, NERA estimate[5] that the expected real market returns have averaged 9.6%, since the collapse of Lehman Brothers in September 2008. This is significantly above the historic market return and reflects the higher forward looking risk premium.



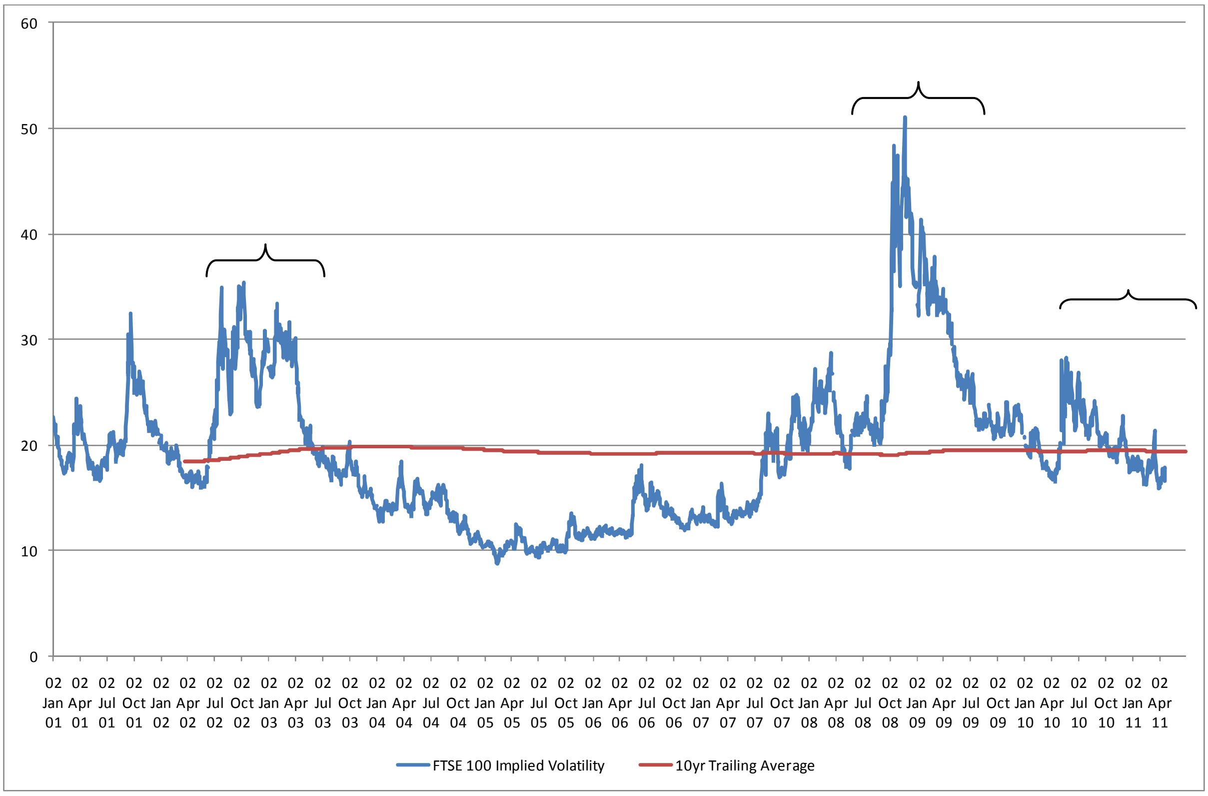
Source: Bloomberg, Consensus Forecast and NERA analysis

[5] NERA op. Cit., Slide 12

Source: UBS Investment Research

Implied volatility for the FTSE 100, continues to remain higher than in recent non-crisis periods, from 2003 to 2008. There have been three major crises during the last 10 years:

- Bursting of the "Dot.com" Bubble
- Credit Crisis
- Sovereign Debt Crisis



Source: Bank of England

Recent FERC decisions

The average[6] of recent FERC decisions for electricity transmission operators is a real return on equity (RoE) of 8.5%, before 'adders'.

The average real RoE for electricity transmission is 70bps higher than the average of 7.8% allowed for distribution, over the same period.

FERC provides an uplift on the return allowed for new investment, especially that which is non-routine. It allows[7] for 'adders' for new investments that reduce congestion or increase reliability, as well as other incentive adders, e.g. for membership in an integrated structure. Recent FERC decisions have tended to allow 100 to 150bps, as well as other incentives, such as allowances for abandoned construction. These rules are intended to encourage transmission investment. This is recognised to benefit consumers

[6] NERA, op. cit., slide 46

[7] FERC Orders 679 and 679-A 'Promoting Transmission Investment through Pricing Reform', July 20, 2006 and December 22, 2006, respectively

by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

Cash Flow Duration

Proposals for RIIO-T1 have the effect of significantly increasing the duration of cash flows as a result of:

- Extending length of price control period to 8 years;
- Lengthening depreciation lives for new assets to 45 years; and
- Extending period over which revenue adjustments resulting from incentives, as a result of adjusting the RAV (i.e. the 'slow pot' component)

The CAPM, however, is a single period model and cannot capture the impact of the duration of cash flows on the required return.

However, as shown[8] in recent Oxera reports and ENA submissions, there is evidence on multi-period returns, which can be used to assess the impact of the profile of cash flows on the cost of equity.

The Inter-temporal Capital Asset Pricing Model (ICAPM) extends the CAPM into a multiple period setting. This is necessary to assess how the required return varies with cash flow duration.

In summary, the impact of duration on the required return can be disaggregated into two parts:

- term premium effect; and
- Beta effect

The term premium is clearly demonstrated by the observed yield curve and is estimated to be around 50bps.

Brennan and Xia (2006) state[9] 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. Further analysis undertaken by Oxera shows that empirical estimates[10] of cash flow betas for regulated utilities are within the range where expected returns will increase with duration.

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[8] Oxera (2011), 'What is the cost of equity for RIIO-T1 and RIIO-GD1?', February 14th

ENA (2010), 'Implementing the RIIO recommendations in GD1 and T1: Determining the cost of capital', November 10th

Oxera (2010), 'What is the impact of financeability on the cost of capital and gearing capacity?, May 27th

[9] Brennan, M and Xia, Y (2006),'Risk and valuation under an Intertemporal Capital Asset Pricing Model', *Journal of Business*, **79**:1

[10] Oxera (2011), 'The impact of longer asset lives on the cost of equity: estimating cash flow betas, July

Required return on equity

Ofgem’s range for the cost of equity has been derived for an average network operator. However, for SPT, a number of factors increase the cost of equity, including:

- Risk from the relatively large capex programme;
- Relatively small size of SPT compared to National Grid;
- Compensation for extended asset lives and greater duration of cash flows;
- Risk of shortfall in the allowed cost of debt when interest rates rise.

Although the middle of Ofgem’s range, which is based on a pure CAPM approach, may be appropriate for an average network operator, SPT requires a higher return to compensate for:

- the additional risk arising from its relatively large capex programme (relative to its RAB) – 50bps;
- the longer duration of cash flows in RIIO-T1 – 50bps; and
- the forecast increase in the risk free rate – 70bps.

Taking into account these factors, we conclude that SPT requires a return at the top end of Ofgem’s range, which is broadly consistent with historic market returns.

Overall, the top end of Ofgem’s published range of 7.2% (real, post-tax) is the minimum return required to attract and retain sufficient equity into SPT to finance the required increase in investment and ensure continuing financeability.

Financeability

We target financial ratios which are consistent with an A/A- credit rating, with the majority at A. This is necessary to offset the risks which are embodied within the price control package and to allow for deterioration in cash flows in adverse circumstances. The major risks we have taken account of are:

- Shortfall of debt indexation when the cost of debt increases;
- Residual risk that Ofgem’s cost of debt index cannot be cost effectively matched;
- Real price effects which increase costs above the RPI; and
- Not achieving targets set for the incentive mechanisms.

Furthermore, at BBB, SPT would face the prospect of being unable to refinance or raise additional debt finance during a period of financial turmoil, as became evident following the collapse of Lehman Brothers. There continues to be significant risk of a sovereign debt crisis with contagion spreading to other countries and the global financial system through the exposure of international banks. Uncertainty also surrounds geo-political developments, especially in the Middle East and North Africa.

Ofgem's proposed cost of debt indexation, which uses a 10 year trailing average, as at the previous 31 December, results in a shortfall when the cost of debt increases. The cost of debt is expected to increase significantly, as a result of:

- Reversal of quantitative easing;
- Tightening of monetary policy to meet the inflation target;
- Implementation of Basel III rules that strengthen the regulatory framework for banks;
- Solvency II requirements for capital adequacy and risk management for the European insurance sector; and
- Likelihood of crowding out of non-financial companies.

Although Ofgem claim that indexation of the cost of debt reduces risk, a residual amount of risk remains where a company cannot cost effectively track the index. Oxera have estimated[11] that a margin of 10bps, above the index, is required to allow for a range of factors. However, the relatively large increase in SPT's RAV, increases this by a further10bps, as it increases SPT's exposure to changes in the market cost of debt.

We have considered whether a weighted index, reflecting annual RAV additions, would help to reduce the shortfall by more closely matching the pattern of debt issuance. However, in practice, a further lag which would be introduced, so as to facilitate the reporting and review of the relevant expenditure, which would tend to exacerbate the shortfall.

In addition, SPT bears the cost of transaction and pre-funding costs, which we estimate to amount to 20-30bps, for a company of our size.

We provide a full analysis of anticipated Return on Regulatory Equity (RORE) in section 9.5, where we demonstrate an inherent negative skew of outcomes arising from the various incentive mechanisms.

Financial Ratios

Statutory ratios are calculated using projected statutory interest costs which give the true external facing metrics visible to investors. This is preferable to calculating 'regulatory' ratios which use modelled interest costs and therefore misleadingly enhance the true financeability position of SPTL.

These targeted ratios would meet the criteria of comfortable investment grade quality which would be sufficient to attract funding for the large capex investment required during RIIO-T1. Lower ratios would put this at risk in the face of potential shocks as detailed later.

[11] Oxera (2011), "What is the link between debt indexation and allowed returns?", July

Moody’s gives three times the weight to PMICR (which it refers to as Adjusted Interest Cover Ratio) and Net Debt / RAV than to the other two ratios. For SPT, PMICR becomes the binding financial ratio during RIIO-T1.

Furthermore, ratings agencies consider smaller companies to be higher risk, because of:

- Higher asset concentration;
- Higher revenue concentration; and
- Greater exposure to event risk.

For example, Moody’s requires[12] better ratios from water only companies compared to water and sewerage companies, for a given level of leverage, in order to achieve the same credit rating.

In 2009, Ofwat determined, for water only companies (WoCs), an uplift of

- 0.2 on the adjusted interest cover ratio (PMICR)
- 0.5 on the interest cover ratio (ICR)
- 5 percentage points lower for the ratio of net debt to RAV

Ofwat said that its ratios for WoCs were higher because the credit rating agencies required greater headroom in cash flows for WoCs to account for the impact of specific or asymmetric risks.

Analysis by NERA[13], for water only companies, shows that WoCs with similar ratios to WaSCs are often rated one notch lower.

We have used the methodology adopted in the Competition Commission’s Report[14] on Bristol Water as the primary basis for assessing financeability. This set out its interpretation of Moody’s rating methodology as:

Moody’s credit rating	Gearing (net debt/RCV)	Adjusted cash interest cover	S&P ‘equivalent’ credit rating
A2	50-60	Above 2.5	A
A3	60-68	1.8-2.5	A-

[12] Moody’s, Industry Outlook – UK Water Sector: Stable Rating Outlook Factors Broadly Neutral Credit Impact of Draft Determinations for 2005-10, 2004.

[13] NERA, Ofwat’s PR09 Draft Determinations on the Small Company Premium: A Review A Report for the Water-Only Companies,September 2009

[14] Competition Commission, Report on Bristol Water, Appendix O Financeability, 2010, TABLE 3, page O4

Baa1	68-75	1.6-1.8	BBB+
Baa2	75-85	1.4-1.6	BBB
Baa3	Above 85	Below 1.4	BBB-

These correspond with the Competition Commission's target values for gearing and adjusted cash interest cover.

This Report:

- Focuses on the two financial ratios to which Moody's gives greater weight
  - i.e. gearing and adjusted cash interest cover
- Provides a more finely graded set of ratios and corresponding credit ratings
  - e.g. distinguishes between A- and BBB+ ratings
- Establishes a precedent for future appeals by network operators

Moody's uses four key credit metrics[15] when assessing the credit risk of a regulated network. These are:

- Adjusted Interest Cover Ration (Adjusted ICR)
- Net Debt / Regulatory Asset Value (Net Debt / RAV)
- Funds From Operations / Net Debt (FFO / Net Debt)
- Retained Cash Flow / Capital Expenditure (RCF / Capex)

Within these financial ratios, Moody's gives three times the weight to Adjusted ICR and Net Debt / RAV than to the other two ratios.

The other main credit metric which is used, for example, by Standard & Poor's is FFO / Interest (FFO Interest Cover).

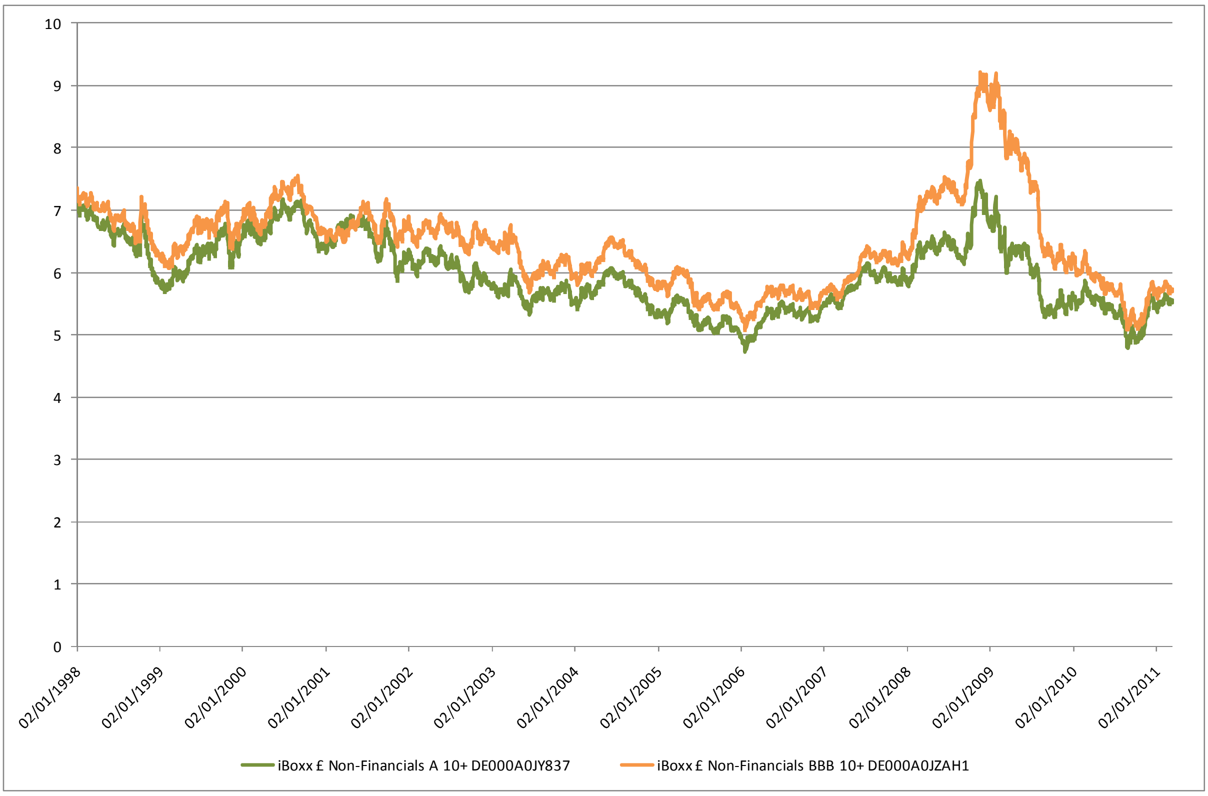
Aside from the reasons inherent to this package for credit ratios for SPT for RIIO-T1 being consistent with an A/A- grade rating, we also consider the following factors:

- BBB would be suboptimal and increase WACC further
- higher gearing would raise the cost of equity
- equity bears the cost of the shortfall on the cost of debt
- rating agencies consider smaller companies to be higher risk
- following the credit crisis, rating agencies are more demanding

Ofgem's proposed allowance for the cost of debt is determined as the 10 year average of A and BBB rated sterling non-financial corporate bonds, with maturities of greater than 10 years. Over the last 10 years, the additional debt premium on BBB rated debt has

[15] Moody's Investor Service, Regulated Electric and Gas Networks, August 2009, pages 17-20

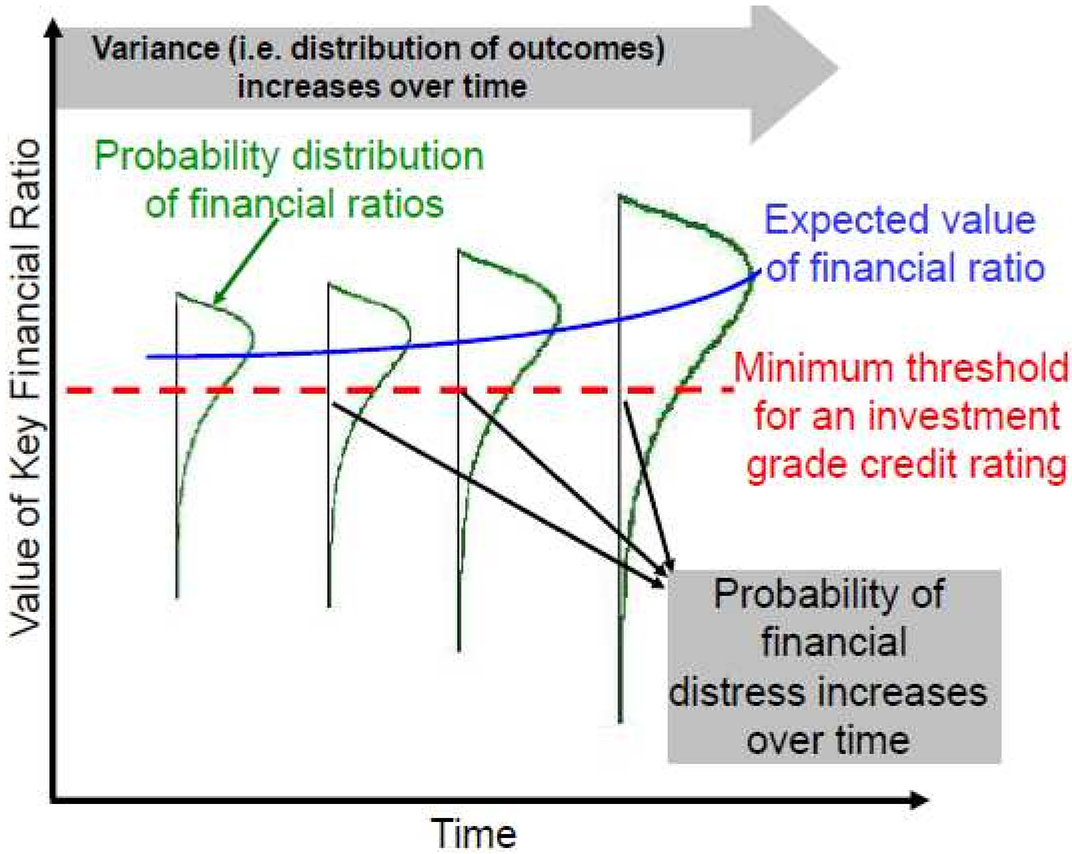
averaged 53bps above that on A rated. The cost of debt for BBB rated bonds would therefore be 27bps higher than the proposed index.



Source: Markit iBoxx

The boundary between A- and BBB+ for gearing is 68%. Moving to this higher level of gearing would increase the equity beta by a factor of (1-0.5)/(1-0.68) = 1.56 (i.e. from 0.95 to 1.48), which would raise the cost of equity by 293bps.

Typically, rating agencies have adopted a three year horizon for assessing financial ratios. However, the probability distribution of financial ratios widens with the time horizon. Consequently, the probability of financial distress increases over time. The proposed longer price control exposes SPT to higher cumulative risk. This increases the need for stress testing of financial ratios.



Source: NERA Illustration - qualitative only (not quantitative modelling)

In its 2011 Outlook for UK utilities Fitch highlighted that:

> "From a credit risk perspective particularly the downside risk is relevant for the analysis. If the price control cycle is extended and there are no other changes to the regulatory regime, then this clearly increases credit risk."

In its Industry Outlook 2010 for EMEA electric and gas utilities, Moody's warn that:

> "All other things being equal, to the extent that business risk increases, that will probably result in a tightening of guideline leverage ratios at the same rating level."
>
> And
>
> "the sheer size of the investment programmes, coupled with potentially tighter regulatory constraints in some regimes, could lead to rating pressure if tariff increases are insufficient or untimely, and capital structures become overburdened with debt."

Gearing

We assume notional gearing of 50%, which is consistent with an A credit rating and appropriate for a company of SPT's scale as a result of:

- the increase in risk due to SPT's much larger capital expenditure programme, relative to its RAV in comparison with TPCR4;
- the risks embodied within the price control, including
    - shortfall of debt indexation when the cost of debt increases;
    - real price effects which increase costs above the RPI; and
    - in adverse circumstances, not achieving targets set for the incentive mechanisms
- the negative skew of the distribution of RoRE outcomes; and
- the longer price control period, which exposes SPT to higher cumulative risk

A BBB rating would be sub-optimal and increase the overall WACC, as well as limit access to external finance during periods of capital market disruption.

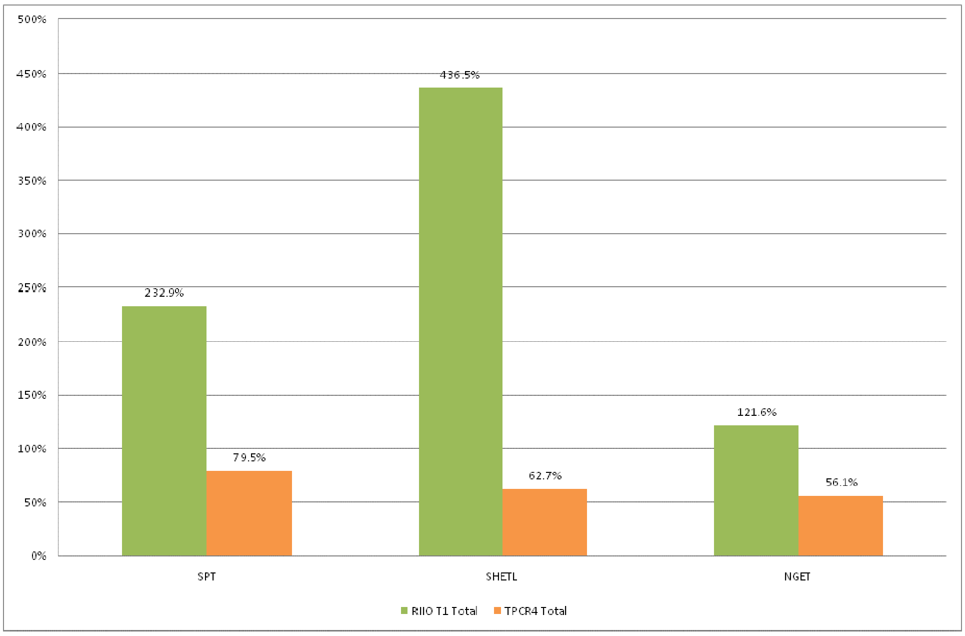
We are concerned that, should there be another period of stress within the capital markets, for example, as a result of contagion from a sovereign debt crisis, refinancing will be available only to companies with higher investment grade credit ratings. This risk should be mitigated by the initial credit metrics and gearing assumption.

Moreover, in view of recent criticisms of the rating agencies, their rating methodologies and criteria may be become more demanding in future, which is of particular concern in view of the long term nature of transmission projects.

Furthermore, we note that a gearing level of 50% would not appear to be inconsistent with other UK and international regulatory decisions, e.g. in comparison with US rate cases in 2010 with a range of 50%-60%, electricity operators in Europe with a range again of 50%-60% and Ofwat's 2009 final determination for Water only Companies of 52.5%

Neither is our assumption on notional gearing inconsistent with actual gearing in the energy sector. SPT's actual gearing at 31st March 2011 is 40.8% and Iberdrola's 44.3% at 30 June 2011.

Operational leverage may be expressed as the ratio of fixed costs to total costs. Therefore, taking capital expenditure (capex) as a fixed cost, the impact of the capex to RAB ratio on operational gearing becomes more apparent.



The capex to RAB ratio is indicative of the extent to which operating income fluctuates with changes in revenues. Operating leverage thus amplifies the effects of the wider business cycle or macroeconomic environment on a firm's profits—and hence the sensitivity of firms' returns to market returns (or beta). To the extent that capital and operating expenditure is fixed over the control period, the expenditure to RAB ratio indicates the degree of operational leverage. Higher capex to RAB ratios result in greater operational leverage and thus higher business risk.

In assessing the scale and complexity of the capital programme of a regulated energy network, Moody's[16]:

> "makes an assessment of a regulated network's capital expenditure by considering (i) the size of this capex programme relative to the issuer's asset base (expressed in percentage of its Regulatory Asset Value or total fixed assets), and (ii) the complexity of this programme, i.e. the type of assets to be built and associated technical issues (e.g. offshore transmission) as well as the relative concentration of challenging projects within the issuer's total capex programme."

Moody's further note:

> "under this sub-factor, we assess the execution risk associated with a potentially large capital expenditure programme, which may in turn weaken financial metrics in case of delays or cost overruns."

Moody's conclude:

> "Issuers will score "Aaa" through "B", depending on the size of their capital programme measured in terms of annual total capital expenditure (including both maintenance and

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[16] Moody's Investors Service, Regulated Electric and Gas Networks, August 2009, page 13

> enhancement spend, gross of any subsidies) as a percentage of total net fixed assets or regulated asset base. A network with one large and complex project accounting for the majority of its capital programme will also score "B" regardless of the relative scale thereof."

Similarly, for water companies, Moody's states[17]:

> "companies facing a very large investment programme compared to their asset base and/or projects of high technical complexity would score at the lower end of the spectrum."

To offset this higher business risk for SPT, Ofgem should lower the notional gearing, compared with TPCR4.

Depreciation lives

To ensure financial ratios consistent with an A credit rating, it is necessary to phase the move to 45 year depreciation lives, for new assets only, over the RIIO-T1 price control period (i.e. depreciation lives, for new assets only, increase linearly from 20 in 2012/13 to 45 in 2020/21). This represents a 'split' and 'stepped' approach. We have modelled straight line depreciation consistent with Ofgem's view.

Without transitional arrangements for longer deprecation lives, financial ratios would deteriorate significantly.

Financial Ratio	Deterioration by 2020/21
Net Debt /Closing RAV	+2.6%
FFO/Interest	-1.1
Retained Cash Flow / Net Debt	-4.2%

The advantages of phasing the change in deprecation lives for new assets, so as to ensure financeability, are:

- the need for other advancement of revenue is avoided;
- step change in depreciation is smoothed; and
- customers contribute similar amounts towards capital maintenance throughout RIIO-T1.

[17] Moody's Investors Service, Global Regulated Water Utilities, December 2009, page 15

Depreciation lives for assets existing at 31 March 2013 remain at 20 years, which is consistent with Ofgem's decision as set out in the March 2011 RIIO-T1 Strategy document. We set out our rational which supports this position in detail in our response to Ofgem's December Strategy consultation.

Taxation

We are generally supportive of Ofgem's decisions as set out within the March Strategy Decision Document and have reflected these in our Business Plan. We believe that the operation of the tax clawback mechanism to be defined by the Licence should mimic our modelling assumption regarding the process of equity injection as described below.

We welcome the decision to apply extant legislation and that where these are not implemented that differences will be treated as pass-through. This protects both customers and shareholders from impacts outwith their control.

We note the decision to adjust revenues for only the excess over the deadband. We had expressed a preference for the whole impact to be reflected but do not consider this to be a sufficiently material departure for us to dispute this approach.

We agree

- that tax should be modelled under EU-IFRS from April 2014
- with the calibration of the deadband
- that the period for spreading the clawback of tax benefit of excessive gearing should be 9 years in respect of any adjustments from previous controls allowed revenues should be reset every 3 years from the tax clawback mechanism for excess gearing during RIIO-T1

We accept that the tax treatment of new incentives can be correctly calculated using the vanilla WACC.

However, in our business plan we have assumed that we would not inject any new equity into the business unless the modelled gearing is more than 5% above the cost of capital assumed gearing level of 50% to reflect likely actual policy. This modelling assumption also serves to leave the gearing level at the end of RIIO-T1 consistent with the assumed level of 50%. It is important that this 5% equity injection threshold is reflected in the tax clawback clauses in the Licence – we would not expect to be penalized because our actual gearing exceeds 50% whereas the modelled gearing allows for gearing to be 5% above the cost of capital assumed gearing level and, importantly, modelled interest costs are based on debt being a maximum of 5% above assumed gearing.

Consistent with the March 2011 paper on the decision on strategy for RIIO-T1, which concludes[18] that allocations of expenditure to taxation capital allowances pools should be company specific for Transmission electricity companies, we have selected the user defined option. We have also included additional modelling which automatically calculates the allocations of expenditure to capital allowances pools based on the final (per the Final Proposals) expenditure allowances contained in the "IQI" tab rows 45 to 99 – these rows reflect 25% of the licensee's expenditure forecast and 75% of Ofgem's expenditure forecast. The additional modelling automatically links to the tax pool allocations rows in the "Common Inputs" tab.

Included in the financial model is additional modelling that we have produced (and has been adopted by Ofgem) to remove the tax dilution impact of TIRG projects. This has arisen for the following reason:

In row 52 of "Rev Calcs" TIRG revenue is correctly excluded from the taxable profit calculation as TIRG investments are provided with a fixed return which includes the effective tax allowance. Therefore the tax allowance in row 21 is supposed to reflect the tax allowance relating to the non TIRG element of the price review. However, the tax deductions for interest payable and capital allowances include elements relating to TIRG investments (i.e. the debt on which interest is calculated includes TIRG related debt and the capital allowances pools include TIRG investment). As a result, there is a double count on the TIRG related interest and capital allowances deductions, as these have already been accounted for in the fixed return. Therefore, taxable profit is lower than it should be and the resulting tax allowance in row 21 for the non TIRG element of the price review is being diluted.

Capitalisation

We note that Ofgem recognise the capitalisation rate to be one of several financeability levers which Companies are at liberty to propose with suitable justification. SPTL regards the transitional arrangements surrounding the move to useful economic asset lives for the purposes of calculating the depreciation as being the main lever to address financeability concerns.

As such we see no strong reason to depart from an intuitively appealing base position which simply reflects annual statutory capitalisation rates. This is the approach we have therefore adopted within our Business Plan.

[18] Ofgem (2011) "Decision on strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1 Financial issues", Appendix 4 – Tax methodology, paragraph 1.15, March

This approach sees our assumed fast/ slow money split begin at around 5%/95% at the beginning of RIIO-T1 and ending at around 16%/84% by the end of the period reflecting the significant front ended capex forecast. The average forecast capitalisation rate is about 93%.

We are mindful that a capitalisation rate which is different each year may be cumbersome to apply, e.g. as it would require to be reflected through the efficiency incentive 'within period' calculation. As such we would be willing to consider an alternative ex ante average capitalisation rate across the full period provided that revenues remained NPV neutral after adopting the alternative approach should this be less complex to apply.

Pensions

We have reflected all relevant decisions within our Business Plan.

We note that many well established pension principles are reflected in the March Decision Document and that many issues are treated in a similar way as DPCR5. As such we are in agreement with many of Ofgem's decisions.

Where we have held alternate preferences, e.g. the timing of true up adjustments with respect previous controls and deficit funding rate of return we do not consider these to be sufficiently material departure for us to dispute this approach.

Our Business Plan submission includes the updated deficit as at 31 March 2011 applying a regulatory fraction of 4.8% and we have reflected the TPCR4 pension costs true up agreed with Ofgem in June 2011.

Profiling

Our expectation is that there will be a significant step change in allowed revenues between the roll over year of 2012/13 and the first year of the RIIOT1 period. This arises largely from the interaction of the increase in capital expenditure and the profile of depreciation allowances. In the absence of a theoretically discrete roll over year this would normally be addressed by smoothing revenues over the longer full period. We have recommended to Ofgem that revenues are smoothed in a way that minimises or removes this step change. In practice this would mean moving revenues into the roll over year from the RIIOT1 period in an NPV neutral manner. Our Business Plan approach does not reflect any such profiling at this stage in the interests of clarity.

9.3 Financial Results – Base Case

This section details the forecast statutory financial position of SP Transmission resulting from the planned capital expenditure and operating costs over the 8 years of RIIO-T1. This section considers revenues before assessed impacts of incentive mechanisms. These are explained in section 9.5.

Highlights

- Average annual revenue £409m
- Closing RAV increases by £1,700m to £3,186m
- New Equity of £375m
- Debt increases by £825m to £1,563m
- Gearing at the end of RIIO-T1 49.1%
- Credit ratios A-

Financial Model

The model we have submitted is based on the version of the Regulatory Financial Model issued by Ofgem on 14th June 2011. We have amended the model to correct any modelling mistakes that we have discovered. In addition we have included some additional modelling to ensure that both trade creditors and allocations of expenditure to taxation capital allowances pools are automatically adjusted to reflect any different expenditure assumptions that Ofgem might make. Details of the modelling corrections and additional modelling have been sent to Ofgem on 29th June 2011 and 21st July 2011. These details are also included in Appendix 2.

Finally, we have included additional modelling to calculate the forecast statutory financial position. This builds on the Regulatory Financial Model and includes the same resulting revenues, operating costs, capital expenditure and working capital. However, in two important respects the statutory financial position differs from the regulatory financial model:

- Interest costs reflect forecast actual interest rates for the business and calculates interest on average debt compared with the regulatory assumptions in the Regulatory Financial Model which calculates interest on opening debt and the cost of debt assumed in the regulatory cost of capital.
- Dividend is calculated on the actual equity element of the RAV (i.e. RAV less closing debt) as opposed to the Regulatory Financial Model which calculates the dividend on the RAV less the assumed debt based on the notional gearing in the regulatory cost of capital.

This statutory modelling gives realistic funding costs with the resulting impact on taxation, dividends, required equity and debt.

Regulatory Financial Model Assumptions

1. Cost of capital

   Our cost of capital assumptions are set out in the table below:

Cost of capital assumptions	TPCR4 Roll-over	RIIO-T1
Cost of Debt	3.25%	3.20%
Cost of Equity	7.00%	7.20%
Gearing	60%	50%

   The TPCR4 roll-over assumptions reflect Ofgem's indicative position contained in the April 2011 TPCR4 roll-over consultation paper. Our position on cost of capital is unchanged from that contained in our May response: cost of equity and cost of debt should remain unchanged at 7.0% and 3.75% respectively; and, in order to mitigate the increased risk associated with a larger capital expenditure programme (relative to RAV), we support the case for use of lower notional gearing for both of the Scottish TOs.

   The rationale for our RIIO-T1 cost of capital assumptions are set out in 9.2 Financial Inputs.

2. RAV depreciation lives

   Consistent with the decision in Ofgem's March 2011 strategy decision paper existing assets at 31 March 2013, including new expenditure on projects already started under the transmission investment for renewable generation (TIRG), will continue to use the existing 20 year life.

   The combination of our capital expenditure profile, which is weighted towards the earlier years of RIIO-T1, and the move to 45 years asset lives for post 1st April 2013 RAV additions have negative short term cash flow implications. In order to mitigate this we have proposed a transitional move to 45 year asset lives, for these new assets only, over the RIIO-T1 price control period. This strategy on asset lives reduces the negative cash flow impacts arising from Ofgem's decision to move to useful economic lives as the basis for regulatory depreciation allowance whilst delivering the goal of sustainable long term financeability and inter-generational equity.

Asset lives will increase linearly from 20 in 2012/13 to 45 in 2020/21 as set out in the table below.

Year of spend	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Asset life	20	23.125	26.25	29.375	32.5	35.625	38.75	41.875	45

RAV asset lives remain at the life allocated to it in the year of expenditure until fully depreciated – for example RAV additions in 2013/14 will retain a life of 23.125 years for the life of that asset.

3. Balance Sheet

The Business Plan model reflects the balance sheet position as at 31st March 2011 per the 2010/11 regulatory accounts.

4. Capitalisation

The capitalisation assumption we have applied in our Business Plan simply reflects the annual statutory capitalisation rates. This approach sees our assumed fast/slow money split begin at around 5%/95% at the beginning of RIIO-T1 and ending at around 16%/84% by the end of the period reflecting the significant magnitude of the capex forecast. The average forecast capitalisation rate is about 93%.

Capitalisation rates	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Capitalisation %	94.7%	95.3%	94.1%	91.8%	91.9%	92.0%	91.0%	83.5%

5. Allocations of expenditure to taxation capital allowances pools

   Consistent with the Ofgem March 2011 Strategy decision paper that allocations of expenditure to taxation capital allowances pools should be company specific for Transmission electricity companies (Financial Issues paper Appendix 4 paragraph 1.15) we have selected the user defined option. As noted above we have also included additional modelling which automatically updates the allocations of expenditure to capital allowances pools based on the final (per the Final Proposals) expenditure allowances contained in the "IQI" tab rows 45 to 93 – these rows reflect 25% of the licensee's expenditure forecast and 75% of Ofgem's expenditure forecast. The additional modelling automatically links to the tax pool allocations rows in the "Common Inputs" tab.

6. Equity Issue

   We have selected the User defined option. For practical purposes our modelling assumes that we would not issue any new equity into the business unless the modelled gearing is more than 5% above the cost of capital assumed gearing level of 50%. It is important that this 5% equity injection threshold is reflected in the tax clawback clauses in the Licence – we would not expect to be penalized because our actual gearing exceeds 50% whereas the modelled gearing allows for gearing to be 5% above the cost of capital assumed gearing level. The only circumstance under which we would expect to suffer penalty under the tax clawback is where actual gearing is higher than the modelled position.

7. IQI additional allowance

   We don't consider it to be valid to include any additional income at this stage because of the mechanism uncertainties. However we have considered this as part of our RORE analysis and as part of the assessed impact of incentive mechanisms in section 9.5.

8. TPCR4 Capex Incentive

   We have included additional modelling to calculate the TPCR4 capex incentive based on our forecasts of capital expenditure. The resulting revenue impact is less than £1m. There is no certainty regarding this value as it will eventually be trued up to reflect actual capital expenditure. So, for the purposes of our revenue calculations we have not included this in 2012/13 revenues.

9. Inflation

We have retained the inflation assumptions contained in the model issued by Ofgem on 14th June 2011.

Assumption for Inflation	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
RPI Forecast	4.58%	3.68%	3.28%	2.93%	2.72%	2.61%	2.56%	2.54%	2.53%	2.53%

10. Dividends

We have retained Ofgem's working assumption of 5% of the Equity element of nominal RAV.

Statutory Financial Position Assumptions

The assumed interest rates reflect the weighted average interest rates associated with the current Scottish Power UK debt of £1.2billion. We have assumed that any new debt required will be obtained at these average rates.

Assumption for Interest rates	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Interest rates	6.91%	6.90%	6.90%	6.90%	6.90%	6.90%	6.56%	6.56%	6.56%	6.56%

Revenues

Our Business Plan for the eight years to 2020/21 anticipates that our capital expenditure investment requirements will be £2,048m (2009/10 prices and excluding related party margin). The following table breaks down this total capital expenditure into the funding mechanism categories.

Funding mechanism category	Total RIIO-T1 capital expenditure (£m 2009/10 prices)
Ex ante base	973

TIRG	110
Volume driver - connections	43
Volume driver – non-load	68
Uncertainty	854
Total	2,048

Based on the regulatory financial model assumptions our total modelled revenues amount to £2.5 billion (2009/10 prices) over the eight years of RIIO-T1.

The split of revenues is shown in the table below.

RIIO-T1 revenues (£m 2009/10 prices)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Ex ante base plus excluded	220	233	242	256	259	263	265	268
TIRG	22	26	30	21	19	18	18	17
Volume driver - connections	0	0	1	1	1	1	2	3
Volume driver – non-load	0	0	0	0	1	2	3	4
Uncertainty	6	18	30	41	49	55	60	63
Total	248	277	303	319	329	339	348	355

We estimate that, on average, the impact of our business plan on customers' bills is that the annual charge per customer will increase by £ 0.13 in each year of RIIO-T1 from an estimated £424.

Our expectation is that there will be a significant step change in allowed revenues between the roll over year of 2012/13 and the first year of the RIIOT1 period. This arises largely from the interaction of the increase in capital expenditure and the profile of depreciation allowances. In the absence of a theoretically discrete roll over year this would normally be addressed by smoothing revenues over the longer full period. We have recommended to Ofgem that revenues are smoothed in a way that minimises or removes this step change. In practice this would mean moving revenues into the roll over year from the RIIOT1 period in an NPV neutral manner. Our Business Plan approach does not reflect any such profiling at this stage in the interests of clarity.

Note that once the TIRG projects move into the normal RAV (i.e. 5 years after construction is completed) then these TIRG associated revenues become part of base revenue

Summary Statutory Financial Statements

The following tables show the forecast statutory financial position of SP Transmission which can be found in greater detail within the submitted model and in the Financial templates. The highlights over the eight years of RIIO-T1 are (all nominal):

- Total Turnover £3,274m
- Average turnover £409m
- Capital Expenditure £2,597m (excl related party margins)
- Equity Issue £375m
- Debt increase £825m

P&L (£m Nominal)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Turnover	292	335	376	407	431	454	478	501
Operating profit	209	239	268	296	313	323	345	361
Interest	-56	-69	-84	-96	-99	-97	-103	-104
Tax	-37	-39	-42	-46	-49	-52	-55	-59
Dividend	-43	-52	-61	-64	-68	-78	-82	-85
Retained profit	73	79	81	90	97	96	105	113

Cash flow (£m Nominal)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Operating cash flow	253	285	312	346	375	390	416	426
Tax paid	-15	-17	-16	-18	-21	-23	-26	-30

Capital Expenditure	-417	-471	-384	-287	-293	-301	-290	-153
Interest & Dividend	-99	-121	-145	-160	-167	-175	-185	-189
Cash flow before financing	-278	-324	-233	-119	-106	-109	-85	54
Equity Issue	101	131	0	0	143	0	0	0
(Increase)/Decrease in Debt	-177	-193	-233	-119	37	-109	-85	54

Balance Sheet (£m Nominal)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Fixed Assets	1533	1916	2347	2682	2914	3147	3383	3603	3680
Working capital & Tax	-87	-100	-105	-101	-98	-101	-103	-105	-97
Debt	-739	-916	-1109	-1342	-1461	-1424	-1533	-1618	-1564
Deferred Tax	-138	-157	-180	-205	-231	-258	-287	-315	-341
Net assets	569	743	953	1034	1124	1364	1460	1565	1678

Regulatory Asset Value

Regulatory asset value increases by £1,700m to £3,186m.

Closing RAV is shown in the following table

Closing RAV (£m Nominal)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Closing RAV	1486	1832	2217	2502	2676	2847	3019	3174	3186

Financeability

The target financial ratios for assessing our financeability are set out in the table below. We have targeted A- in our base position before considering the impact of incentive mechanisms. Ratios are discussed further in section 9.2. Moody's regard Net Debt/RAV and PMICR as the most important ratios (they attribute a weighting of three times more importance to these two ratios than the others). The Net Debt/RAV and PMICR ratios are those used by the Competition Commission in their report on Bristol Water in 2010. The other three target ratios have been extrapolated from the ratios quoted in the March 2011 Strategy decision paper (Financial Issues paper paragraph 4.9).

Target credit ratios	Range at A-
FFO interest cover (x)	3.0 – 4.0
Net Debt / RAV (%)	60 -68
FFO/ Net Debt (%)	10 - 16
PMICR using RAV depreciation (x)	1.8 – 2.5
RCF / Capex (x)	1.5 – 2.0

The financial ratios that result from our plan are shown in the following table.

Financeability ratios	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Average
FFO interest cover (x)	4.2	3.9	3.5	3.4	3.6	3.8	3.8	3.8	3.8
Net Debt / RAV (%)	50.0	50.0	53.6	54.6	50.0	50.8	51.0	49.1	51.1
FFO/ Net Debt (%)	26.0	24.2	22.0	22.4	24.9	24.0	24.2	25.4	24.1
PMICR using RAV depreciation (x)	2.1	1.8	1.6	1.6	1.7	1.7	1.7	1.7	1.7
RCF / Capex (x)	0.3	0.3	0.4	0.6	0.6	0.6	0.7	1.4	0.6
Regulated	3.8	4.0	3.7	3.5	3.8	3.8	3.7	3.7	3.7

Equity/EBITDA									
Regulated Equity/Earnings	3.1	3.3	3.1	3.0	3.3	3.3	3.3	3.2	3.2

The first three ratios comfortably meet or exceed the A- targets. PMICR is below the A- target for all years except 2013/14 and 2014/15. RCF/Capex is significantly below the A- target. However, Moody's believe that utilities undergoing a large capex programme who do not benefit from accelerated depreciation are expected to score this metric in the range 0.5 – 1.0 (March 2001 Strategy decision paper Financial Issues paper notes to figure 4.1); but in 2013/14 to 2015/16 the ratios are still below this lower threshold.

We have also included Regulated Equity / EBITDA and Regulated Equity / Earnings as they were quoted in Ofgem's strategy decision paper; however we have no clear view of target thresholds.

Overall we consider this base scenario to provide A- quality ratios and therefore sufficient comfort to protect against a range of risk factors.

9.4 Management of Risk

Introduction

The introduction of a new regulatory framework under RIIO-T1 allied to an unprecedented increase in required capital expenditure combine to present a considerable challenge to Transmission companies in terms of managing risk whilst providing appropriate returns to investors and ensuring a fair deal to current and future customers.

The electricity transmission companies are responsible for network planning, stewardship of their assets and operational decisions over time, to ensure any risk to delivery of primary outputs is managed as cost-efficiently as possible.

Under RIIO model, network companies need to identify areas on the network where work may be required to maintain their assets to reduce risks to network operation and delivery of the primary outputs, both during the price control period and in the future. Our asset risk management policy sets out a clear approach for our management of network risk in terms of operation, maintenance and investment, and are linked to secondary deliverables.

Under the RIIO Framework, network risk is dealt with in secondary deliverables complemented by an incentive framework.

Alongside operation risks a number of financial risks present themselves arising from amongst other things the lengthening of the regulatory period, the introduction of a debt indexation methodology, the lengthening of the period of remuneration, exposure to real price effects and an increased emphasis upon incentive mechanisms.

Furthermore the RIIO-T1 period follows close on the heels of a global financial crisis and will be set against a backdrop of concerns surrounding sovereign debt crises and geo-political uncertainty as witnessed recently in the Middle East.

In this section we highlight five of the key manifestations of risk, how they arise and how we seek to manage these within our Business Plan. The five key risk areas upon which we focus are:

- Delivery/ Output Risk
- Interest Rate Exposure via Indexation
- Exposure to Real Price Effects
- Increased emphasis upon Incentives
- Duration of the RIIO framework

We have not attempted to specifically add each impact to arrive at a proposed a cost of equity in excess of the top end of Ofgem’s range but set these out as evidence for proposing that top end value and for proposing a financeablity package which in the round provides investment grade credit ratios, offering acceptable safeguards against these inherent risks to the Business Plan.

Delivery/ Output Risk

It has been recognised by SP Transmission that significant investment in assets and change to normal patterns of system use is expected to increase and continue throughout the review period in order to meet government energy policy objectives. These must also take place while the need to deliver increased levels of asset modernisation is becoming a significant delivery issue.

Our delivery plans are therefore set within the context of a longer term delivery strategy which will ensure the investment requirements of asset stewardship can be integrated with new connections and capacity reinforcements.

We will deliver the significant levels of investment proposed via a high degree of programme management structure and control designed to ensure that the interactions between issues can be managed.

We have also retained a degree of flexibility within our plans to allow us to resolve conflicts arising within the programmes. Our overall approach is to develop the non load programme in such a fashion that it can be linked and co delivered alongside the projects driven by reinforcement and generation needs which are envisaged over the price review.

- To ensure that required volumes are achieved it is considered that more modernisation projects must be pre engineered and available within a delivery window than will actually be worked upon.
- The consequences of external issues, such as planning consent, outage availability etc, will then be managed by choosing which individual scheme elements can proceed within the available outage opportunities.
- Non load schemes can therefore flex around changes in the reinforcement programmes within the review period.
- Additionally a significant volume of transformer replacement and 132kV substation renewal projects need to be overlaid on the investment programme.
- A degree of smoothing has also been considered within these programmes to manage the sensitivity around supply chain and resource dependencies, for example in the area of overhead lines.

Iberdrola Support and Delivery Model

SPT considers that opportunity for a fundamental change in delivery can be taken which will take advantage of the improved leverage available via a global purchasing organisation with is described more fully under the Procurement heading below.

SPT has and intends to maintain an established and formal relationship with Iberdrola Engineering and Construction (IEC). IEC was created in 1995 and is now one of the leading energy engineering companies in the world with a presence in over 30 countries across Europe, Middle East, America and Africa. Its current project portfolio is in excess of 2.5 billion Euros, with a turnover in excess of 1.4 billion Euros in 2009. Although the company is headquartered in Spain, 87% of its project portfolio is abroad and more than 80% of its sales are from outside the Iberdrola Group. The current worldwide workforce stands at more than 2400 people of 48 different nationalities, more than 80% of which are professionally qualified in engineering/ project delivery disciplines.

This organisation and its preparations to increase its capacity to support SPT in managing the delivery of Transmission investment

The expertise available within IEC and the associated methodology means that work elements within projects can be disaggregated and supply of materials and services re-aggregated under appropriate procurement strategies. By this means it is possible to open up new delivery options and introduce fresh and competitive capacity from the supply chain incorporating local, national and global suppliers as required and where competent and cost effective. Through this approach the technical and commercial risks are managed and controlled in house by IEC engineering teams and project managers. Standardisation is more readily achievable than historically where different main contractors have to be engaged directly to Engineer Procure and Construct their individual projects. SPT believe that this new approach is more appropriate where major programmes of work have to be integrated and delivered onto a system which is heavily utilised in supporting established users and is subject to high levels of depletion when key outages are taken. A significant level of control is achieved through this approach and increased levels of activity and interactions between projects can be reliably managed.

Procurement

SPT will purchase its equipment, goods and services efficiently through Iberdrola's Global Purchasing Organisation. While the level of investment proposed in RIIO T1 is a significant increase in volume over TPC4, when considered within the Global market within which Iberdrola Group Procurement operates the relative volume increases are much less dramatic and SPT is confident that efficient investment can be procured in line with its proposed business plan.

Outage Delivery

Key to success is the control and management of changes in outage plans. Earlier outage certainty will allow key sensitivities to be robustly monitored through project and programme level governance reports and corrective action agreed with the key parties which will ensure critical outage windows are adhered to by all parties. SPT will seek to secure a greater level of certainty both in the delivery aspects of site work and in system access.

SPT has scoped its investment plans in detail during the preparation of this business plan. By having an established view at an early stage several benefits will be realised. In addition to identifying opportunities for standardisation which will reduce the scale of the procurement task and this will also lead to higher levels of consistency and drive generic solutions to problems identified through construction and commissioning. These factors will reduce the likelihood of overruns in the medium term and improve confidence levels among stakeholders.

SPT is now therefore able to plan more carefully and accurately the outage requirements.

By bundling modernisation projects together and into outage plans necessary for other works, SPT believes it will be able to secure agreement from other stakeholders through improved forward planning and formal mechanisms to resolve issues.

SPT has engaged with the NETSO and shared its overall vision of the extent of the modernisation plans and is continuing to develop the forward programme through to a stage by stage outage plan with emphasis on key interactions between the various modernisation works and proposed load driven schemes.

Consenting

Consenting is key to the critical path for any major project and has been a key area of focus within our assessment of the deliverability of our plans.

Obtaining all necessary consents is dependent on outside agencies, such as local authorities, providing consent approval to competent planning applications in realistic timescales.

Also, the advent of considerable onshore wind in Scotland has led to Scottish landowners becoming much more aware of the value of land necessary to connect wind hence agreement of landowner consents can take some time, particularly if we are to ensure that connections and associated infrastructure are delivered cost-efficiently.

For every type of major project scenario we typically deliver Consenting & Wayleave templates have been developed. These specify the optimal process for obtaining the necessary consents across our schemes. They also lay out key metrics and milestones that will be monitored on an ongoing basis.

As part of the building of our investment plan the Consenting process has featured heavily. A resource management study has been undertaken to manage all future load and non load projects against the rolling programme for RIIOT1

Staffing

Like most established organisations in the UK, SP Transmission has an ageing workforce and we recognise that to successfully meet the challenges of RIIO T1 we must have an HR strategy that addresses the requirement to maintain our workforce skills and experience, in an environment of extensive growth for transmission but also with an ageing workforce.

Against this Business Plan up to 1,500 new and incremental directly associated jobs will require to be created in the SPT franchise area during this period. Approximately 53 of which will be within SP Transmission business directly, approximately 160 within our principal contractor IEC and approximately 1,200 -1,300 across our full contractor base. This excludes any clerical or business support requirements.

Also during this period because of attrition and retirement SP Transmission will need to recruit a further 98 staff bringing our total projected recruitment requirement of 152 staff

Interest Rate Exposure via Indexation

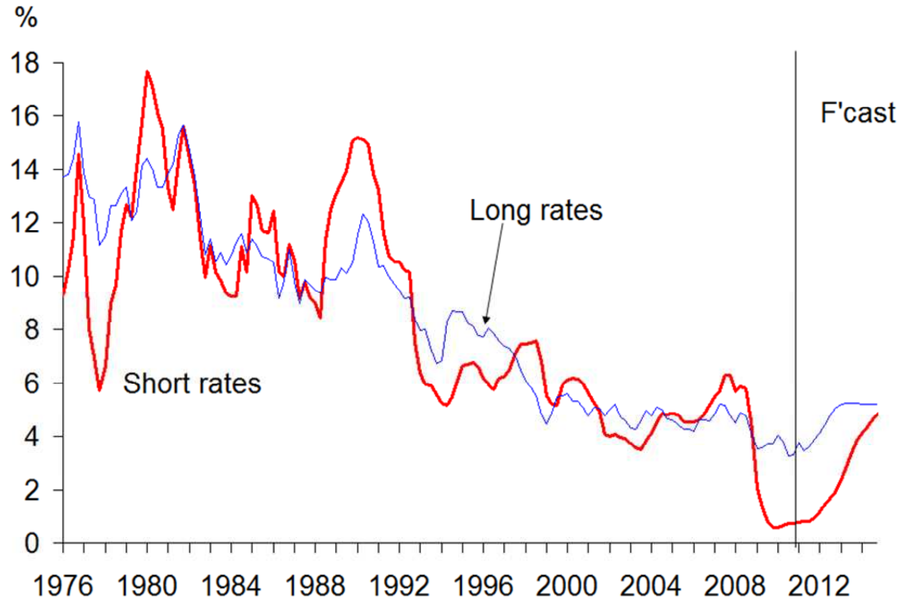
Ofgem's proposed cost of debt indexation, which uses a 10 year trailing average, as at the previous 31 December, results in a shortfall when the cost of debt increases. The cost of debt is expected to increase significantly, as a result of:

- Reversal of quantitative easing;
- Tightening of monetary policy to meet the inflation target;
- Implementation of Basel III rules that strengthen the regulatory framework for banks;
- Solvency II requirements for capital adequacy and risk management for the European insurance sector; and
- Likelihood of crowding out of non-financial companies.

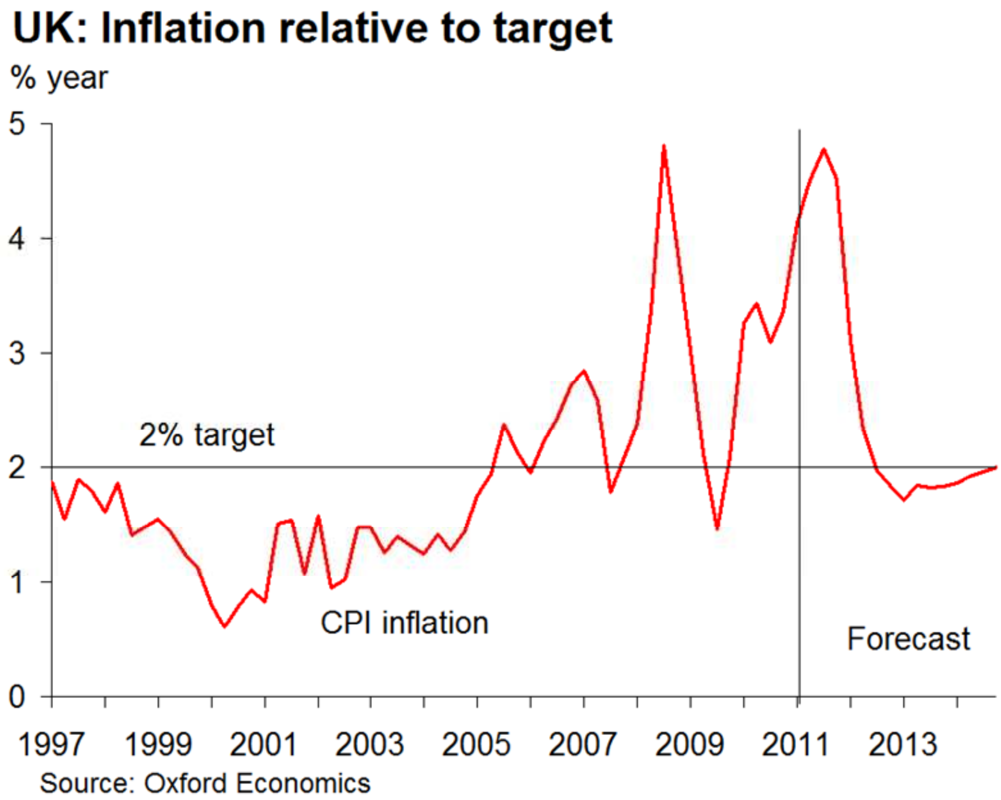
Oxford Economics forecast[19] that nominal long term interest rates will rise by 1.5 percentage points by 2014. This results in a greater increase in real interest rates as inflation is forecast to fall back to the target.

[19] Oxford Economics (2011). "How long will interest rates stay low?", presented at World, UK and Emerging Markets Outlook Conference, London, 22nd June

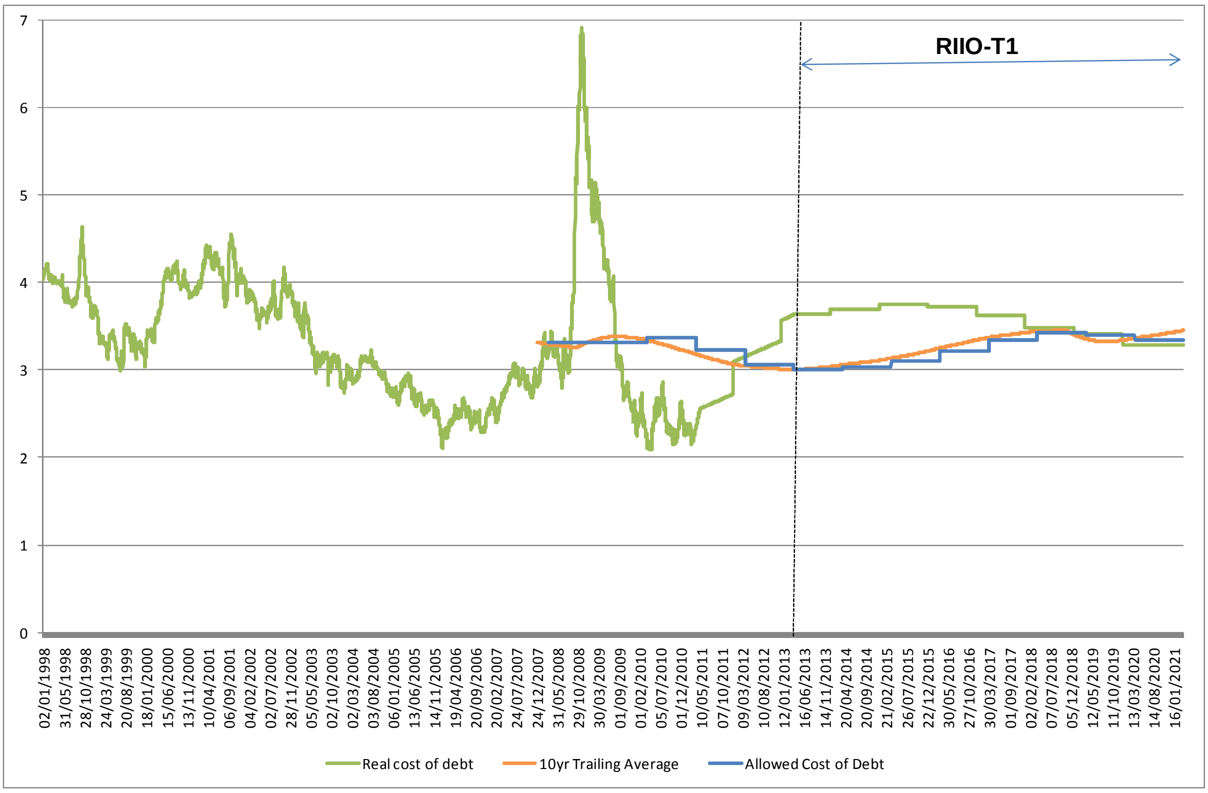
UK: Nominal interest rates



Source: Oxford Economics



The resulting shortfall in the allowed cost of debt, as interest rates rise, is illustrated below for the current forward curve, which is derived from yield curves for sterling corporate bonds, with 10 year maturity and credit ratings of A- and BBB, which were taken from Bloomberg.



As can be seen from the above chart, the allowed cost of debt will fall significantly below the cost of debt when interest rates rise. Based on the forward curve, the shortfall, on average, over RIIO-T1 is expected to amount to an equivalent of 33bps on the cost of debt. The shortfall is expected to peak at 73bps in 2015.

The impact of this prolonged shortfall will be to adversely impact financial ratios, as interest payments will be greater than allowed for. For example, an interest cover of 4 times calculated using an illustrative cost of debt of 3.2% real, which is equivalent to, say, 6% nominal, would be reduced to 4/(6.33/6) = 3.8 when adjusted for the projected shortfall of 33bps. Furthermore, the peak shortfall is projected to be 73bps, which would further reduce the interest cover ratio to 4/(6.73/6) = 3.6.

We have considered various alternative forms of formulation of the method of indexation including weighting within the reference period but have concluded that there is no straightforward means to mitigate this exposure.

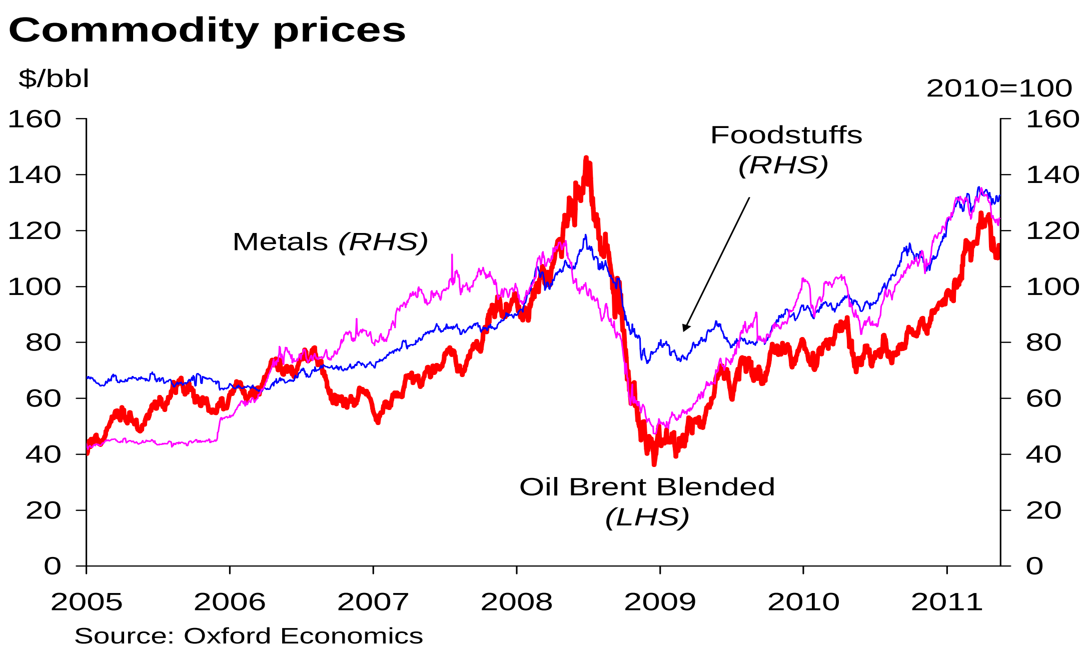
Instead we consider this as part of our wider financeability proposals which includes an allowed cost of equity at the top of Ofgem's range and combination with transitional arrangements surrounding asset lives.

Exposure to Real Price Effects

SPT is exposed to the risk of real price increases above the RPI. Commodity prices are notoriously volatile and cannot be predicted with confidence. However, recovery from the recession and rapid growth in emerging economies, including China and India, are forecast to lead to commodity prices continuing to increase above the Retail Prices Index (RPI).

The World Bank in its latest Global Economic Prospects notes[20]:

"The spread of political unrest in the Middle East and North Africa could push crude oil prices much higher in the shorter term, especially if there is disruption to a major oil producer. Stronger demand from China could boost metals prices by more than currently expected, and continued supply constraints could further aggravate markets. Given low stock levels, agricultural (and especially food) prices will remain sensitive to adverse weather conditions and energy prices. Moreover, at current or higher oil prices, biofuels production becomes an increasingly attractive use of land and produce, likely increasing the sensitivity of food to oil prices."



We have carried out analysis in conjunction with other network operators using external advice from First Economics[21], included as Appendix 3. Whilst this has enabled us to include our best view of labour and material price increases, there inevitably remains considerable uncertainty in this area, particularly over an eight year price control period and at a time of great international economic and geo-political uncertainty.

[20] World Bank, Global Economic Prospects, June 2011

[21] First Economics, Real Price Effects, 30 June 2011

This cannot be mitigated further by conducting any further predictive analysis and instead is reflected in a proposed financeability package that delivers comfortable investment grade credit ratios.

Nevertheless, in view of the longer price control period we are seeking a cap on SPT's cumulative exposure to real price effects of 20% over RIIO-T1. In the unlikely event that cumulative real price effects exceed 20%, above cumulative RPI, then we propose that the excess increase be reflected in increased revenue, for example, by enhanced indexation (i.e. above the normal RPI indexation). Real price effects would be calculated as a weighted index of components, which reflects SPT's mix of inputs, as set out in Table 2.1.4b (of the main Business Plan tables).

Increased emphasis upon Incentives

Although in normal circumstances we expect to achieve targets which are set for incentive mechanisms, there remains the risk that in adverse circumstances these targets may not be achieved. This would lead to a downward adjustment to revenue in a particular year, which would adversely impact cash flows and financial ratios, even if the targets are met, on average, over time.

For example, as regards energy not supplied, the performance in any one year may be dominated by a single large event. Over the last 10 years, there have been eight incidents which have resulted in more than 50MWh of energy not supplied. Moreover, the single largest incident, Windyhill, resulted in 437MWh of energy not supplied. Such large events would dominate performance in a particular year.

Such a large event, which would result in a revenue reduction of £3.5m (at an indicative £16,000/MWh with an efficiency rate of 50%) would have a significant impact on financial ratios, especially in the first part of the RIIO-T1 period. In particular, PMICR, which is the binding ratio, would be reduced by 0.1 and lower the indicative credit rating by one notch.

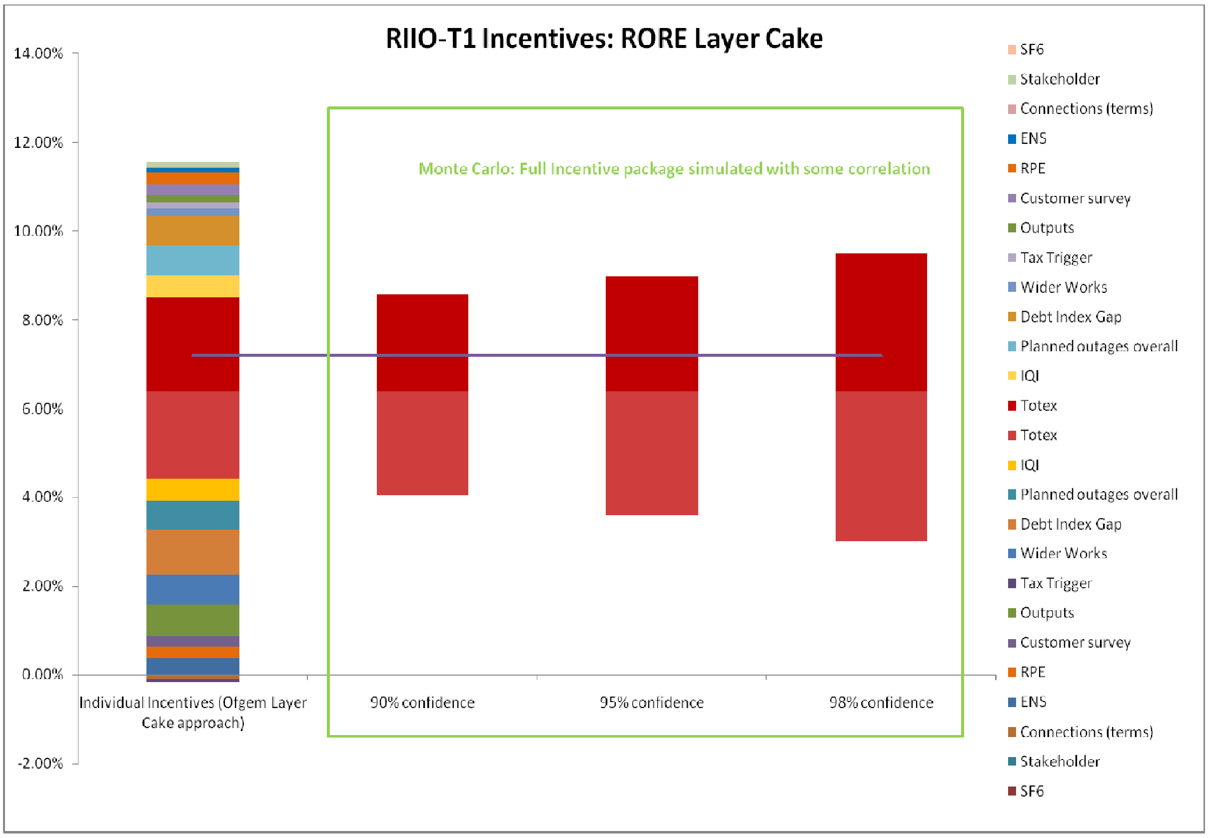
We provide a full analysis of anticipated Return on Regulatory Equity (RORE) in the form of a technical paper as an appendix to this chapter where we demonstrate an inherent negative skew of outcomes arising from the various incentive mechanisms. This analysis includes the impacts of the indexation of debt already described above.

Our estimate of the impact of the RIIO-T1 Outputs and Incentives Package (with other risks) is that it reduces the expected return on regulatory equity by 86 basis points from 7.2 % to 6.34 % (real).

The spread of possible outcomes around this mean value is 6.4 percentage points (downside) and 5.2 percentage points (upside), giving a RORE range of -0.1 % minimum to 11.5 % maximum.

	RORE	Variance from Mean	Variance from Allowed
Min	-0.1%	-6.4%	-7.3%
Mean	6.3%		
Max	11.5%	5.2%	4.3%

The contribution of individual risk components to the overall package is shown in the chart below.



Duration of the RIIO framework

We believe that intuitively, that measures to extend the period over which investors will receive returns whether that be related to the inherent regulatory risk from lengthening the price control period, by extending the period for remuneration depreciation allowance or by extending the period over which incentive rewards or penalties are settled presents additional risk for investors.

In addition as discussed further in the Finance Section of this paper we present academic evidence.

For example, Brennan and Xia (2006) state[22] 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. Empirical estimates of cash flow betas for regulated utilities are within the range where expected returns will increase with duration for utilities.

Separately, the problem of "time inconsistency" has been exacerbated by lengthening the regulatory period where TOs have to rely on the consistency of regulatory decisions over a longer period of time.

Detailed analysis of these impacts have been undertaken on our behalf by NERA. This is included as Appendix 1 to our Financial Issues section. We estimate that extension of asset lives increases financing costs by up to 50 basis point of WACC at 50% gearing.

Uncertainty mechanisms

We propose a limited number of uncertainty mechanisms for RIIO-T1, which will mitigate the impact of developments outside of SPT's control. These are:

- RPI indexation of revenue
- Licence fee and business rates pass through
- Cost of debt indexation
- Pension deficit repair
- Tax trigger
- Re-openers for protection of national infrastructure
- Volume driver for connections expenditure
    - To accommodate generation beyond [3516 MWh]
- Wider reinforcement works

[22] Brennan, M and Xia, Y (2006),'Risk and valuation under an Intertemporal Capital Asset Pricing Model', *Journal of Business*, **79**:1

- Trigger mechanism
- Within period revenue adjustment on submission of independently verified projects, followed by end of period cost review.

- Disapplication of the price control

RPI indexation of revenue during RIIO-T1 will be applied as set out in Ofgem's decision letter of 1 July 2011. This provides essential protection for SPT from economy-wide inflation, as measured by the RPI, and protection to consumers from potential over-pricing of inflation risk by the network companies.

We agree that there should be no change to the policy for pass through of licence fees and business rates. Licence fees are determined by Ofgem and business rates cannot be accurately forecast for the duration of RIIO-T1.

Cost of debt indexation, pension deficit repair and tax trigger are addressed in the financial issues section.

There should be re-openers to provide protection against additional costs that may arise from requirements of the Centre for Protection of National Infrastructure to enhance security. We accept that there will be two re-opener windows, one in 2015 and the other 2018. We also accept that the materiality threshold will be 1% of allowed expenditure in year one of the RIIO-T1 price control (i.e. regulatory year commencing 1 April 2013), once the efficiency incentive rate (from the Information Quality Incentive) has been applied. However, this amount should be expresses as a percentage of allowed revenue, as this would be more transparent.

We propose a volume driver for connections projects which provides additional revenue if the cumulative amount of generation connection capacity (including that connected prior to RIIO-T1 but excluding high cost projects) exceeds [3516MWh]. This revenue driver would take the value of £48,000 (in 2009/10 prices) per megawatt. This would be very similar to the mechanism set out in Part 2 of Special Condition J5 (Restriction of transmission charges: Total incentive revenue adjustment) of SPT's Transmission Licence, although the rate of return values would need to be adjusted for cost of debt indexation, year by year. Provision should be made for high cost projects where local infrastructure works will exceed £144,000 (in 2009/10 prices) per megawatt (i.e. three times the average value for the revenue driver) of predicted capacity. As for TPCR4, an annual operating cost allowance of 1% of the cumulative gross value of the revenue driver RAV should be included in the revenue adjustment.

We propose the following mechanisms for wider reinforcement works and non-load works which are dependent on load works:

- Volume drivers for over head line (OHL) rebuilding and re-conductoring, by voltage and switchgear

- Within period revenue adjustment on submission of projects which have been independently verified by mutually agreed assessors, followed by an end of period cost review.

The proposed volume drivers are:

- for switchgear
    - 275kV circuit breakers at £1,514,000 (in 2009/10 prices) per bay
- For OHL
    - 132kV OHL rebuild at £225,000 (in 2009/10 prices) per circuit km
    - 275kV OHL re-conductoring at £432,000 (in 2009/10 prices) per circuit km

Again, an annual operating cost allowance of 1% of the cumulative gross value of the revenue driver RAV should be included in the revenue adjustment.

We propose that provision for within period determination should be adopted for projects similar to those which currently are classified as TIRG or TII and where there is considerable uncertainty surrounding relatively large projects. We currently propose that the following projects would be included:

- East /West 400kV Upgrade and series compensation
- East Cost (Kincardine-Harburn) 400kV Upgrade
- Western HVDC link
- Dumfries and Galloway Strategic Reinforcement
- Hunterston / Kintyre Link
- East Cost HVDC Link (Firth of Forth)

The first five of these projects will be necessary to deliver our Best View Generation Plans.

The East Coast HVDC link (Firth of Forth) is currently subject to significant debate about the technical scope of its capabilities.

During RIIO-T1 we shall submit independently verified reports, from mutually agreed assessors, which set out the proposed works and necessary expenditure. However, it is essential that provision is made for changes to the scope of works for such projects. Nevertheless, this approach would facilitate a reduction in the number of consultations while providing for protection for customers by avoiding possibly unnecessary or excessive allowances and through the initial direction of the Authority and, subsequently, the end of period review.

We support the continuation of the current policy for disapplication of the price control. With an 8 year price control period there is a greater risk that an efficient and economic network company could find itself in financial distress, which would need to be relieved before the end of the price control period.

9.5 Management of Risk – Methodology & RORE Analysis

SP TRANSMISSION

RIIO T1

Proposed Business Plan
Modelling of Outputs and Incentives

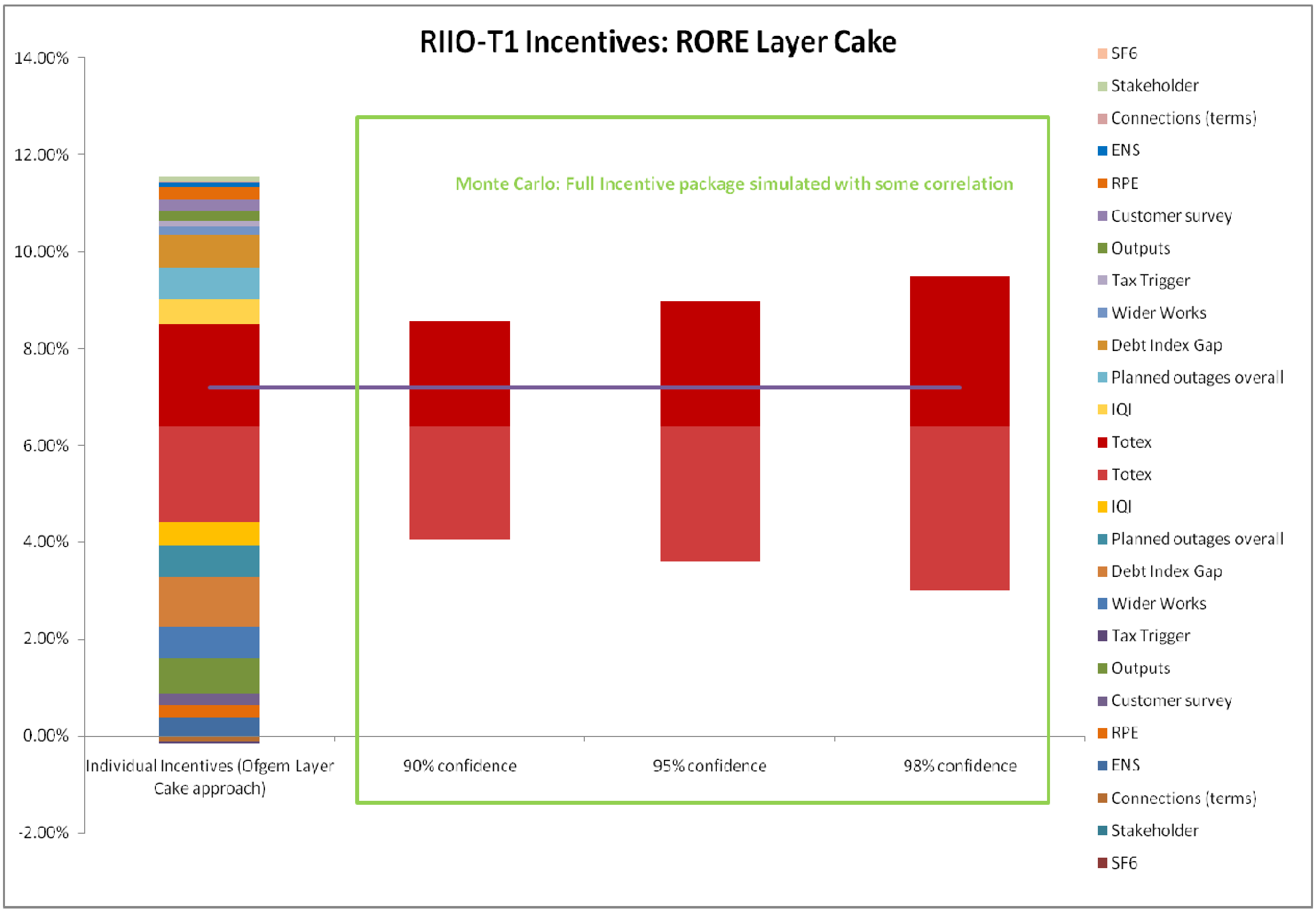
Incentives: Return on Regulatory Equity (RORE)

Our estimate of the impact of the RIIO-T1 Outputs and Incentives Package (with other risks) is that it reduces the expected return on regulatory equity by 86 basis points from 7.2 % to 6.34 % (real).

The spread of possible outcomes around this mean value is 6.4 % (downside) and 5.2 % (upside), giving a RORE range of -0.1 % minimum to 11.5 % maximum.

	RORE	Variance from Mean	Variance from Allowed
Min	-0.1%	-6.4%	-7.3%
Mean	6.3%		
Max	11.5%	5.2%	4.3%

The contribution of individual risk components to the overall package is shown in the chart below.



Layer Cake

The left hand column in the chart has been constructed by stacking our view of the plausible upper and lower limits for individual incentives, and is directly equivalent in presentation to the "Layer Cake" approach used by Ofgem.

Where the component is capped or collared, these limits are used as the upper and lower risk limits, on the basis that a cap or collar only has value if there is a non-trivial risk that the level might otherwise be exceeded. The confidence level here is 100%.

Where there is no limiting mechanism specified, the upper and lower risk limits are taken to be the 1st and 99th percentiles. So for a symmetrical uncapped incentive, the confidence level between our limits is 98%.

Where only one side of the risk has either a natural or an imposed bound a hybrid approach is used. In this case the overall confidence level between limits will be 99%.

In both of the latter cases there is residual risk of an extreme outcome.

The table below shows the RoRE impact of the individual risk components – corresponding to chart column 1:

RORE bp	Lower	Mean	Upper	Downside	Upside
IQI	-64	-16	33	48	49
Totex	-195	2	214	197	212
Wider Works Under delivery	-76	-17	0	59	17
Debt Indexation Gap	-129	-27	40	102	67
Outputs	-90	-19	0	71	19
Customer survey	-24	0	24	24	24
Planned outages overall	-65	0	67	65	67
RPE	-27	0	26	27	26
ENS	-37	0	9	37	9
Connections (terms)	-13	-3	0	10	3
Stakeholder	0	1	11	1	10
Tax Trigger	-9	-4	9	5	13
SF6	-3	-3	-3	0	0
Total	**-732**	**-86**	**430**	**646**	**516**

	Defined Limit
	Percentile Limit

Combined Incentives

The remaining columns have been generated by Monte Carlo simulation of the overall incentive package, with the range illustrated at 90%, 95%, and 98% levels of confidence (the assumptions and methodology used in the simulation are described in detail in the remainder of this document).

The assumed distributions which simulate individual risks have in most cases been estimated, due to the limited availability of relevant historical data. Similarly, although many of the components are likely to be materially correlated there is insufficient data to estimate this with precision.

We have made an assumption that the most controllable of the risks may be moderately correlated. The assumed correlation is detailed in the discussion of Aggregated Risk at the end of Section 2. The uncertainty in the extent to which these components are (or might under certain circumstances become) correlated means that the aggregated modelling approach is more likely to understate risk than the "Layer Cake" approach.

The movement in RORE range from 90% through to 100% confidence limits shows that the overall risk is sensitive to the extremes of the model distributions.

These extremes of distribution will be affected by any uncertainty in the base modelling assumptions.

The table below shows the RoRE impact of the aggregated risk components (with correlation where appropriate) – graph columns 2-4:

Aggregate of Risks (with correlation):-					
Confidence Limits	Lower	Mean	Upper	Downside	Upside
90%	-314	-83	137	231	220
95%	-361	-83	178	278	261
98%	-419	-83	229	336	312
100%	-619	-83	453	536	536

'Layer Cake' vs Overall Incentive Simulation

We conclude that (for a consistent set of assumptions), given the broad consistency between the "Layer Cake" approach and the overall simulation results in the 98-100% confidence range, the "Layer Cake" does not materially understate (or overstate) the total risk relative to the alternative simulation of the overall package.

Given the level of uncertainty about correlation between incentive components at the extremes of the overall distribution, we have used the range of RORE indicated by the "Layer Cake". This has the further advantage of consistency with Ofgem's presentation of their RORE analysis.

Outputs (Financial Impact) Methodology

Primary Outputs and Incentives

Each incentive/output component has been modelled for each year of the price control to enable calculation of the value of those incentives expressed as a percentage of allowed revenue, and to ensure that the impact of any caps/collars on individual years is fully captured.

The central view of the incentive *revenue* impact sums the expected values of the individual incentive components:

$$E(Rev_{incentives}) = \sum_{incentives} E(incentive)$$

This is expressed as basis point impact on the (WACC) return via

$$\Delta_{WACC\ return} = \frac{1000 * E(Rev_{incentives})}{RAV}$$

The equivalent regulatory equity return (RORE) delta is

$$\Delta_{RORE} = \frac{1000 * E(Rev_{incentives})}{(1-g) * RAV}$$

(where g is regulatory gearing).

Where sensitivity to multiple incentives is modelled, the RAV will be appropriately adjusted if necessary (e.g. Equalised Incentive).

The principle can be illustrated at its simplest by calculating the impact of the SF6 Incentive for a single year (2016-17)

We assume that leakage is 0.9% above target (364.5 kg of SF6 at £1.2k/kg)

Pre-tax penalty is £0.44m

Post-tax penalty is £0.34m

Equity return is reduced by £0.34m (in this simple incentive example only the equity return is affected as debt/interest are unchanged)

In 2016, forecast average RAV is £1908m (in this simple example the incentive does not give rise to any RAV adjustment)

At 50% gearing, equity RAV is £954m

$\Delta_{RORE} = \frac{10000*0.34}{954} = 3.6$ basis points

This must be forward valued by 6 months: $Final\ \Delta_{RORE} = \Delta_{RORE}(1 + WACC)^{0.5} = 3.7$ basis points

Revenue

Revenue throughout is real with base year 2009/10

The revenues used where reward/penalty is expressed as a percentage are tabulated below:

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Revenue	242	270	296	312	322	331	340	347
0.5%	1.2	1.4	1.5	1.6	1.6	1.7	1.7	1.7
1%	2.4	2.7	3.0	3.1	3.2	3.3	3.4	3.5
3%	7.3	8.1	8.9	9.4	9.7	9.9	10.2	10.4

The expected values (£m: Table 1) and lower limit (£m: Table 2) of the total revenue impact are tabulated by year below:

TABLE 1: Revenue Impact of EXPECTED VALUE (before tax) of Incentives by year (£m)

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Base Revenue	242	270	296	312	322	331	340	347
1. SF6	-0.15	-0.30	-0.44	-0.44	-0.44	-0.44	-0.44	-0.15
3 Customer Survey	0	0	0	0	0	0	0	0
4. Stakeholder Engagement	0.14	0.15	0.16	0.16	0.17	0.17	0.17	0.14
5. Connections	-0.27	-0.30	-0.31	-0.32	-0.33	-0.34	-0.35	-0.27
6. ENS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
7. Planned outages	0	0	0	0	0	0	0	0
8. Wider Works	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00	-2.00
9. Debt Indexation Gap	-2.1	-2.3	-2.7	-3.0	-3.1	-3.3	-3.4	-3.4
10. Efficiency Incentive	0	0	0	0	0	0	0	0

11. RPE	0	0	0	0	0	0	0	0
12. IQI	-2.01	-2.01	-2.01	-2.01	-2.01	-2.01	-2.01	-2.01
13. Outputs	-3.52	-3.97	-4.02	-2.67	-2.62	-2.62	-2.49	-1.74
14. Tax trigger	-0.41	-0.45	-0.50	-0.52	-0.54	-0.55	-0.57	-0.58
Total	**-10.3**	**-11.2**	**-11.8**	**-10.7**	**-10.9**	**-11.0**	**-11.0**	**-10.0**

(The debt indexation gap reapportions return from equity to debt. However it can be re-expressed as a revenue effect associated with a shortfall between allowed and 'true' WACC)

TABLE 2: Revenue Impact (before tax) of Lower Limit/1st Percentile Outcomes by year (£m)

	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Base Revenue	242	270	296	312	322	331	340	347
1. SF6	-0.15	-0.3	-0.44	-0.44	-0.44	-0.44	-0.44	-0.15
3 Customer Survey	0.0	-2.7	-3.1	-3.2	-3.2	-3.4	-3.5	-3.5
4. Stakeholder Engagement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. Connections	-1.3	-1.4	-1.5	-1.6	-1.7	-1.8	-1.7	-1.8
6. ENS	-7.4	-8.3	-9.1	-9.7	-9.9	-10.1	-10.5	-10.6
7. Planned outages	-7.9	-7.9	-7.9	-7.9	-7.9	-7.8	-7.8	-7.9
8. Wider Works	-9.2	-9.2	-9.2	-9.2	-9.2	-9.2	-9.1	-9.2
9. Debt Indexation Gap	-12.5	-14.5	-16.9	-18.5	-19.3	-20.2	-20.9	-21.1
10. Efficiency Incentive	-23.5	-27.6	-29.3	-21.8	-22.2	-23.0	-22.8	-18.5
11. RPE	-3.8	-4.4	-4.4	-3.0	-2.9	-2.8	-2.8	-1.8
12. IQI	-7.7	-7.7	-7.7	-8.9	-7.7	-7.7	-7.7	-7.6
13. Outputs	-16.5	-17.7	-17.0	-9.4	-8.6	-8.0	-6.7	-2.7
14. Tax trigger	-0.8	-1.0	-1.0	-1.1	-1.2	-1.1	-1.1	-1.1
Total	**-90.7**	**-102.6**	**-107.4**	**-94.7**	**-94.2**	**-95.5**	**-95.1**	**-86.2**

SF6 Incentive

Assumption 1: (£m) SF6 Incentive

Over RIIO-T1 we will install new SF6 equipment as part of our load and non-load capital expenditure programmes significantly increasing our inventory of SF6 mass used in transmission equipment.

Currently almost all transmission assets have been purchased and installed to IEC specifications which vary up to 3% leakage as design rating. Our current leakage rate at over 1.8% of the 40500kg of total installed SF6 gas is on, if not below design standards. In effect, our operating regime is already performing much better than the equipment specification and we have determined that it is not possible to improve the performance further.

For this reason we base our modelling on the assumption of constant leakage at the present level of 1.8% (729kg)

We assume a target moving progressively from 1.8% to 0.9% over first 4 years of price control (0.3% decrease per year) consistent with Ofgem's expressed view of best practice.

Based on the prevailing non-traded annual carbon price recommended by DECC[23], the incentive strength is £1.2k per kg

Percentile	Forecast values (basis points of RoRE)	Forecast values (£m p/a)
0%	-3	-0.44
100%	-3	-0.44

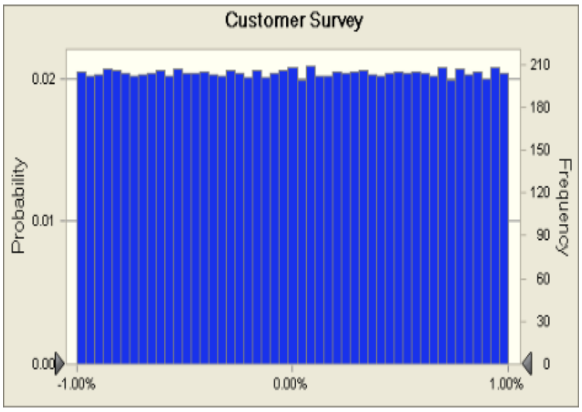
Broader Environmental Incentive

Assumption 2: (£m) Broader Environmental Incentive

Ofgem intend to consult on this incentive. Given the level of uncertainty, we have disregarded the Broader Environmental Incentive in our RORE modelling.

[23] At a non-traded value of £55/tCO2e 1kg of SF6 has a value of around £1200 (using a multiplier of 1kg SF6 to 22,000kg CO2).

Customer Survey



Assumption 3: (Revenue %) Customer Survey

Uniform distribution with parameters:

Minimum	-1%
Maximum	1%
Expected Value	0

No incentive in Year 1 (Benchmark setting)

Reward is based on performance in customer survey. There is assumed to be no incentive in 1st year as reference levels are set. There is little historical information from which to predict an expected outcome.

Equal risk of penalty or reward is assumed. The uniform distribution reflects the risk associated with the small number of customers – there is a non-trivial probability of cap/collar levels of performance (±1% of revenue).

	Forecast values (basis points of RoRE)	Forecast values (Revenue % p/a)
Trials	10,000	10,000
Mean	0.0	0.00%
Median	-0.4	-0.02%
Standard Deviation	13.6	0.58%
Minimum	-23.6	-1.00%
Maximum	23.6	1.00%
Range Width	47.2	2.00%
Mean Std. Error	0.1	0.01%

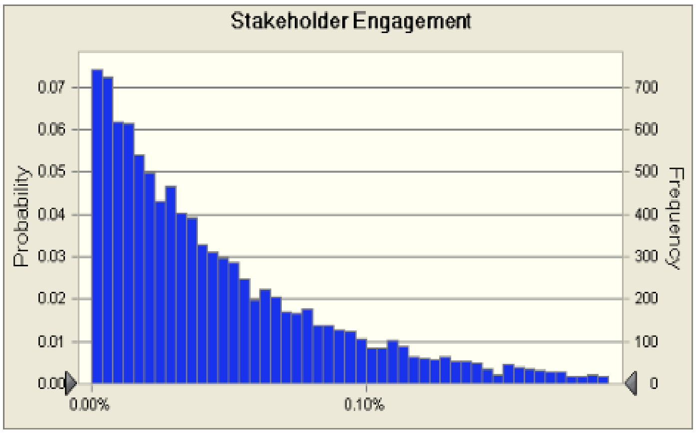
Percentile	Forecast values (basis points of RoRE)	Forecast values (Revenue % p/a)
0%	-24	-1.00%
100%	24	1.00%

Stakeholder Engagement

Assumption 4: (Revenue %)
Stakeholder Engagement

Exponential distribution with parameters:

Rate	2000
Expected Value	0.05%
Collar (% of Revenue)	0.5%

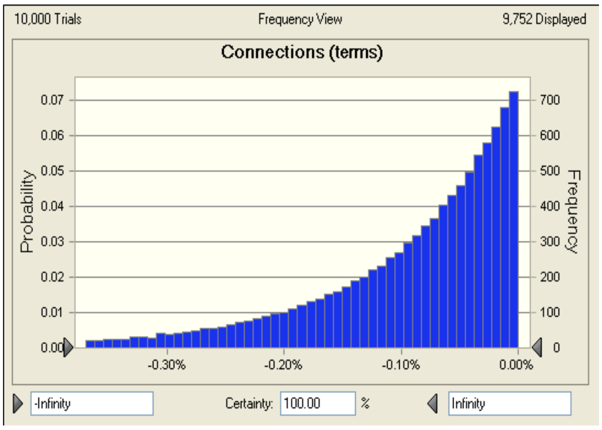


This is proposed as a reward only mechanism. There is no historical data. The distribution is designed to be continuous, and to reflect a strong bias towards the lower end of the range (very low probability of reward) but also the full range of possible upside (limit at 0.5% of revenue).

	Forecast values (basis points of RoRE)	Forecast values (Revenue % p/a)
Trials	10,000	10,000
Mean	1.3	0.05%
Median	0.9	0.03%
Standard Deviation	1.3	0.05%
Minimum	0.0	0.00%
Maximum	11.2	0.43%
Range Width	11.2	0.43%
Mean Std. Error	0.0	0.00%

Percentile	Forecast values (basis points of RoRE)	Forecast values (Revenue % p/a)
0%	0	0
100%	11	0.5%

Connections



Assumption 5: (Revenue % Penalty) Timely Connections Terms

Exponential distribution with parameters:

Rate	1000
Expected Value	-0.1%
Collar (% of Revenue)	-0.5%

This is a penalty-only incentive.

Risks to the timely provision of connections are increasing.

In particular, obtaining all necessary consents is dependent on outside agencies providing consent approval to competent planning applications in realistic timescales.

Onshore wind development has led to landowners becoming much more aware of the value of land necessary to connect wind. Agreement of landowner consents can take some time, particularly if we are to ensure that connections and associated infrastructure are delivered cost-efficiently.

There is no historical data. We have modelled the incentive using a continuous (exponential) distribution designed to reflect a strong bias towards delivery close to target but also to reflect the full range of downside risk.

	Forecast values (basis points of RoRE)	Forecast values (Revenue % p/a)
Trials	10,000	10,000
Mean	-2.6	-0.10%
Median	-1.8	-0.07%
Standard Deviation	2.5	0.10%
Minimum	-13.1	-0.50%
Maximum	0.0	0.00%
Range Width	13.1	0.50%
Mean Std. Error	0.0	0.00%

Percentile	Forecast values	Forecast values

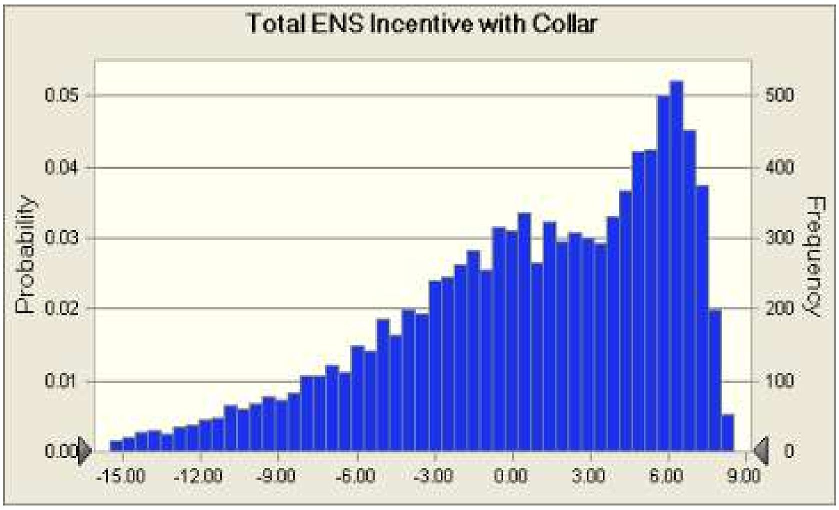
	(basis points of RoRE)	(Revenue % p/a)
0%	-13	-0.50%
100%	0	0.00%

Reliability (Energy Not Supplied:-ENS)

Assumption 6: (£m) ENS/Unplanned Outages

Poisson for event probability, custom (historic) for ENS during event.

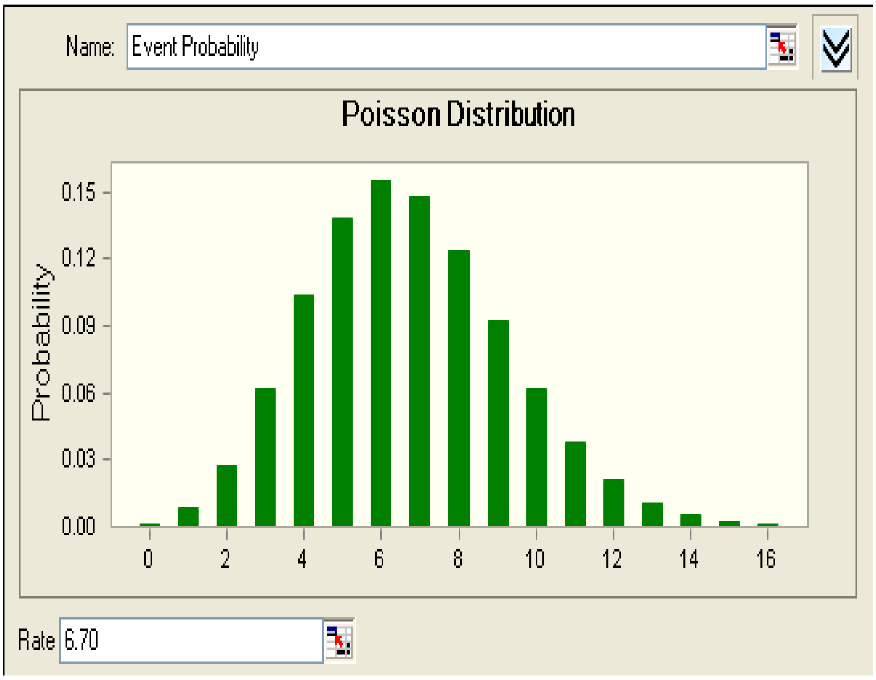
Event frequency p/a (10yr average)	6.7
Expected Value £m (8 year total)	0.71
Collar (% Revenue)	-3%



The efficiency incentive sharing factor is applied to a pre-sharing incentive rate of £16k/MWh.

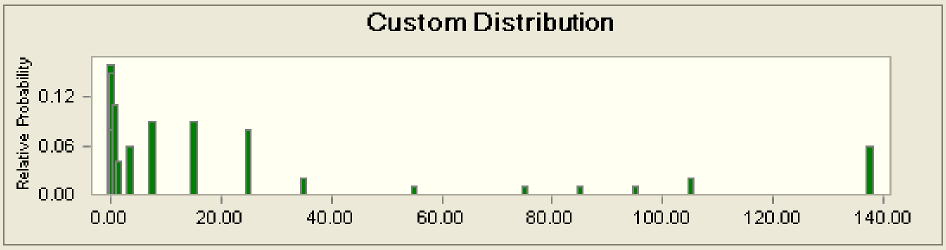
The target has been set at the lower of the proposed ENS values at 130MWh.

The number of ENS events per year is modelled as a Poisson distribution with rate 6.7 (derived from analysis of historical data).



Conditional on an ENS event, the magnitude is modelled using a custom distribution derived from ENS incidents during the past 10 years. The average size of each event is modelled from historic data with an adjustment for the possibility of a large non-excluded event.

Name: Event Size (ENS GWh)



Value	Probability
0.00	0.16
0.10	0.15
0.35	0.08
0.75	0.11
1.50	0.04
3.50	0.06
7.50	0.09
15.00	0.09
25.00	0.08
35.00	0.02
55.00	0.01
75.00	0.01
85.00	0.01
95.00	0.01
105.00	0.02
137.50	0.06

Load Data...

The assumption is that in the next 10 years, 6 events exceed 110 MWh (consistent with 10 year historic data including EE)

Three of these events average 115MWh

One of these events is comparable to Windy Hill (480MWh) but is not excluded.

Two of these events are excluded

The resulting average value in the “largest event” category is 137.5MWh.

Incentive performance has a natural upper limit where ENS = 0. A collar at -3% of allowed revenue is also applied.

	Forecast values (basis points of RoRE)	Forecast values (Revenue £m 8yr total)
Trials	10,000	10,000
Mean	0.4	0.40
Median	1.5	1.40
Standard Deviation	6.0	5.68
Minimum	-36.7	-34.48
Maximum	9.0	8.51
Range Width	45.8	42.99
Mean Std. Error	0.1	0.06

Percentile	Forecast values (basis points of RoRE)	Forecast values (Revenue £m 8yr total)
0%	-37	-34.5
100%	9	8.5

Planned outages

Assumption 7a: (£m Penalty) Planned Outages Policy

Exponential distribution with parameters:

Rate	0.5
Expected Value	-2.00

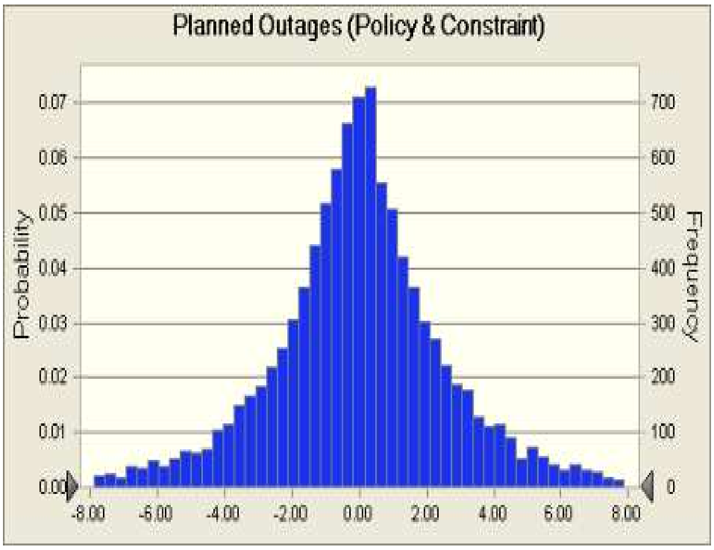
Assumption 7b: (£m) Planned Outages Planned outages

Exponential distribution with parameters:

Rate	0.5
Expected Value	2.00

7a or 7b selected on equal weight (Bernoulli) and combined into single component.

Combined (7a or 7b) EV **0**



It is assumed that TO either benefits from sharing of avoided planned outages or is penalised for failure to comply with outage management policy in any given year, with the two being mutually exclusive.

The value of £10m 'plausible up' is drawn from the Incentives page of Ofgem's financial model as indicative of the intended incentive strength, We have assumed that the penalty element is of equal strength, making the incentive overall symmetric around 0, but have taken a more conservative view of the likely distribution than Ofgem (the combined reward/penalty distribution is narrower around zero than Ofgem's assumption with EVs at ±£2m rather than ±£5m). There is unlimited upside and downside.

Both reward and penalty elements are modelled using exponential distributions as outcomes in both instances are significantly more likely to be small than large.

We believe that a large penalty is equally as possible at any value as the equivalent reward. This is reflected in the decay of the penalty distribution (7a) at the same rate as the reward (7b)

There is assumed to be an equal probability that any given year will result in reward or penalty. Reward/penalty is selected using a Bernoulli random variable.

The aggregate of 7a and 7b outcomes is shown in the chart above.

	Forecast values (basis points of RoRE)	Forecast values (Revenue £m p/a)
Trials	10,000	10,000
Mean	-0.1	-0.01
Median	0.0	0.00
Standard Deviation	24.0	2.82
Minimum	-199.0	-23.41
Maximum	85.0	10.00
Range Width	284.0	33.41
Mean Std. Error	0.2	0.03

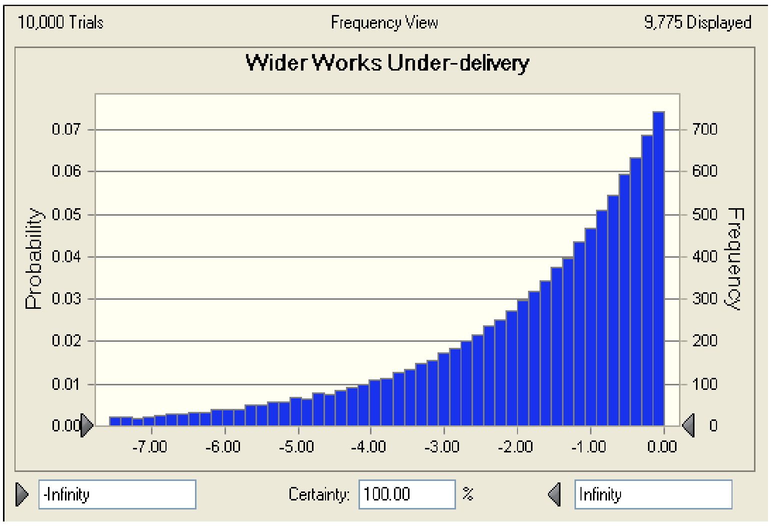
Percentile	Forecast values (basis points of RoRE)	Forecast values (Revenue £m p/a)
1%	-65	-8
99%	67	8

Wider Works (underdelivery)

Assumption 8: (£m Penalty) Wider Works Under-delivery

Exponential distribution with parameters:

Rate	0.5
Expected Value	-2



As Ofgem acknowledges in their Strategy consultation, transmission companies are already incentivised to complete wider works as early as possible. Not only is there a business driver in increasing the business RAV as quickly as possible, but there is also a reputational driver given that the wider system reinforcements are key to supporting Government energy policy.

In terms of overall electricity transmission investment across GB, the Scottish electricity transmission companies continue to have a disproportionate high level of wider system capital expenditure:- expected to range between 25% and 33% of total GB electricity transmission investment. The bulk of this investment will be incurred in technically and environmentally challenging high cost projects.

We note that the level or application of any penalty will be at Ofgem’s discretion. The incentive strength (plausible down of -£10m) is drawn from the Incentives page of Ofgem's financial model.

For the reasons outlined above we feel that in the absence of detailed mechanisms for mitigation, this penalty-only incentive presents a relatively high risk. The distribution is designed to reflect a bias towards delivery close to target but also to reflect the full range of (uncapped) downside risk. Nonetheless our modelling distribution has a more conservative expected value of -£2m as compared to the -£5m identified in the Ofgem financial model.

	Forecast values (basis points of RoRE)	Forecast values (Revenue £m p/a)
Trials	10,000	10,000
Mean	-17.0	-2.00
Median	-12.0	-1.42
Standard Deviation	16.3	1.91
Minimum	-85.0	-10.00
Maximum	0.0	0.00
Range Width	85.0	10.00
Mean Std. Error	0.2	0.02

Percentile	Forecast values (basis points of RoRE)	Forecast values (Revenue £m p/a)
1%	-76	-8.9
100%	0	0

Debt Indexation Gap

Debt indexation using a long run trailing average seeks to reconcile two mutually contradictory desires: the desire to reduce volatility and the desire to track underlying change. However these desires might be balanced, there is likely to be a mismatch between the cost of debt (both embedded and faced in future) by TOs in RIIO-T1 and the index derived from the trailing average.

The risk associated with the Cost of Debt Gap can be estimated using a Monte Carlo simulation based on a (Vasicek) mean-reverting stochastic model with reflection at the zero rate boundary:

$$dr(t) = \alpha(\mu - r) + \sigma dW(t)$$

where α is a constant determining the rate of mean reversion, r is the interest rate, μ is the long-run mean, σ is the volatility and $W(t)$ is a standard Brownian motion.

Calibration

This model is calibrated using the historic mean and volatility of the risk-free rate and credit spread. Three processes are modelled in total: the ten year real zero coupon rate (BoE) and the credit spreads for A and BBB (derived from Bloomberg C41110y and C40510y indices)

Parameters	BoE 10yr real ZC	Spread (A)	Spread (BBB)
α	0.0189	0.0413	0.0338
μ	0.0175	116.3	158.5
σ	0.0028	11.7	15.3

(spread modelled in bp, ZC in %)

The rate forecast is constructed from the simple mean of the A and BBB spreads added to the ten year zero coupon. The index can then be modelled by incorporating the forecasts into a ten year trailing average which triggers a reset of the cost of debt allowance each April.

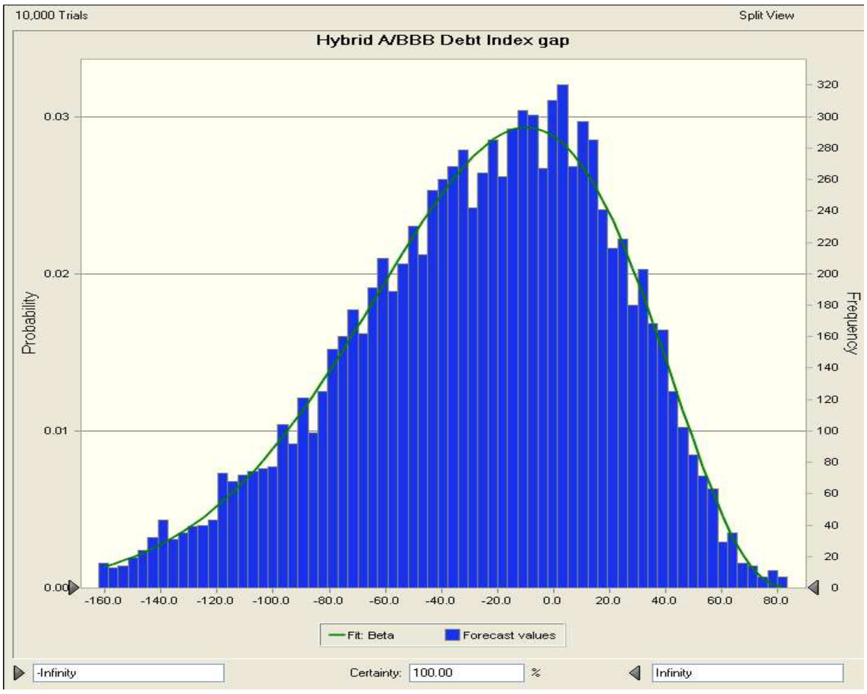
The gap arising from debt indexation is taken to be the average difference over 8 years between the estimate of the instantaneous rate (with 8bp added to represent cost of issuance) and the indexed allowance.

	Forecast values (Average Gap: Interest rate %)
Trials	10,000
Mean	-34.39
Median	-28.69
Standard Deviation	48.30
Minimum	-257.34
Maximum	71.79
Range Width	329.13
Mean Std. Error	0.48

Percentile	Forecast values (Average Gap: Interest rate %)
0%	-257
1%	-165
2.5%	-140
97.5%	44
99%	51
100%	72

The best fit for the resulting distribution is a beta distribution with the following parameters:

Minimum	-366.80
Maximum	84.90
Alpha	11.47
Beta	3.78



This distribution is used to generate the range of RORE return associated with variance between actual and indexed cost of debt.

The -35bp expected value for the index gap is broadly consistent with estimates derived from analysis of the forward curve.

The range of simulated outcomes is plausible as it is calibrated to the observed historic behaviour of zero coupon rates and the relevant spreads.

RORE Simulation

The RORE impact of the indexation of Cost of Debt for each Monte Carlo trial is modelled by adding the forecast difference between allowed and actual interest payments to the debt portion of the total return, which reduces the equity return by the same amount. There is an adjustment to allow for the tax benefit.

Performance is measured with respect to the allowed WACC, not the 'true' WACC as calculated using the market CoD with the same Cost of Equity.

	Forecast values (Overall basis points of RoRE)	Forecast values (Starting gap basis points unadjusted for tax)
Trials	10,000	10,000
Mean	-26.8	-34.39
Median	-22.4	-28.69
Standard Deviation	37.7	48.30
Minimum	-200.6	-257.34
Maximum	56.0	71.79
Range Width	256.6	329.13
Mean Std. Error	0.4	0.48

Percentile	Forecast values (Overall basis points of RoRE)	Forecast values (Starting gap basis points)
1%	-129	-165
99%	40	51

Revenue Impact

An alternative approach to assess the impact of the debt index gap on financeability[24] derives a revenue adjustment based on the difference between return under the allowed WACC and what it would have been using the 'true' WACC. The 'true' WACC is that calculated using the regulatory gearing[25] and Cost of Equity, but replacing the regulatory cost of debt with the observed (or simulated) value.

The following illustrative example ignores any 'return on return' effects:

Base Return	64.41

[24] No account is taken in the modelling of possible feedback effects. It may be expected that as the interest funding gap increases (or other incentives reduce revenue), financial ratios deteriorate to the point of a credit downgrade, which would in itself increase the gap between allowed and actual cost of borrowing. This would amplify the overall risk.

[25] The gearing used is 50% throughout. Higher levels of gearing would obviously materially increase the risk.

Post tax cost of equity	7.2%
Gearing	50.0%
Vanilla WACC (allowed)	**5.2%**
Pre-tax cost of debt	3.1%
1st Percentile debt gap	1.7%
1st percentile cost of debt	4.8%
1st percentile WACC	**6.0%**
Adjusted Return	73.88
Revenue Shortfall	-9.47

Using a more rigorous version of the above, the WACC was recalculated using the 1st percentile and mean of the debt gap obtained from the interest rate simulation described in the Calibration section.

	1st Percentile	Mean
Debt Gap	-165	-34
CoD	4.73%	3.45%
Vanilla WACC	5.96%	5.33%

The revenue impact tabulated below is the difference between the 'true' return under the adjusted WACC and the allowed return.

Revenue Impact: Debt Index Gap		
	1st Percentile	Mean
2013/14	-9.5	-1.6
2014/15	-11.2	-1.8
2015/16	-13.0	-2.1
2016/17	-14.2	-2.3
2017/18	-14.9	-2.4
2018/19	-15.5	-2.5
2019/20	-16.1	-2.6
2020/21	-16.2	-2.6
RIIO T1 Total	**-110.6**	**-17.9**

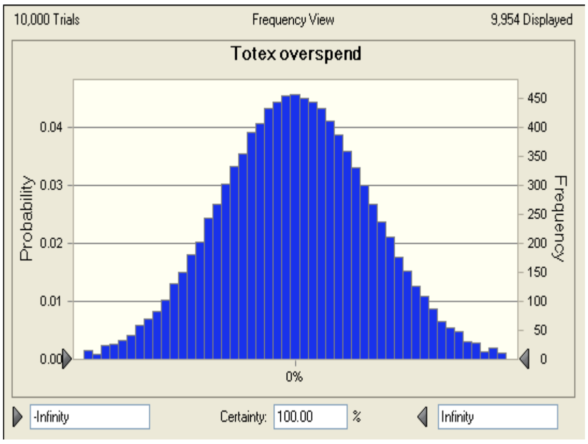
The gap is unprofiled. The average gap over the eight years was used, so the same adjusted WACC is applied in all 8 years. In reality the profile of the gap is unlikely to be flat. This will mean a greater risk than average to the financeability ratios in some part of the price control.

Efficiency Incentive

Assumption 10: (% of Totex) Efficient Underspend

Normal distribution with parameters:

5% cumulative probability	-10%
95% cumulative probability	10%
Expected Value	0



The performance under the Efficiency Incentive is based on a +/-10% variation in total expenditure[26]. The upside case is achieved by performing at the efficiency frontier and containing input costs to below RPI, through careful contracting, cost control and productivity enhancements. The downside case is the result of price or volume shocks compounded by poor cost control.

Totex underspend is modelled independently of RPE impact on efficiency of expenditure. This allows the underspend to be correlated with other incentives while maintaining RPE as an external risk

There is an interaction between Totex and delivery of outputs which ensures that marginally it is preferable to deliver the outputs in full rather than realise an "efficiency" saving. This might be expected to skew the risk towards overspend to ensure delivery of outputs. As we are unable to estimate this we have used a symmetrical distribution.

In the absence of an explicit cap or collar, a normal distribution has been used to capture the tail risk of extreme out or under-performance.

The modelling is based on a range of ±10% in Totex. We've set these as 5th and 95th percentiles of a normal distribution to reflect the tail risk as there's no explicit cap or collar mechanism. The range chosen corresponds to a Standard Deviation of 6%

In our model, we set an over/underspend adjustment percentage for RAV additions. A corresponding Opex adjustment is made via the capitalisation ratio to ensure that the correct Totex impact is modelled.

For a given under (or over) spend, the efficiency incentive sharing factor is applied.

The incentive impact is modelled by applying the overall sharing factor to over or underspend to quantify the total intended incentive impact in the year it takes place rather than at the point where revenue adjustments may occur or benefit might be recovered from return/depreciation on an enhanced RAV.

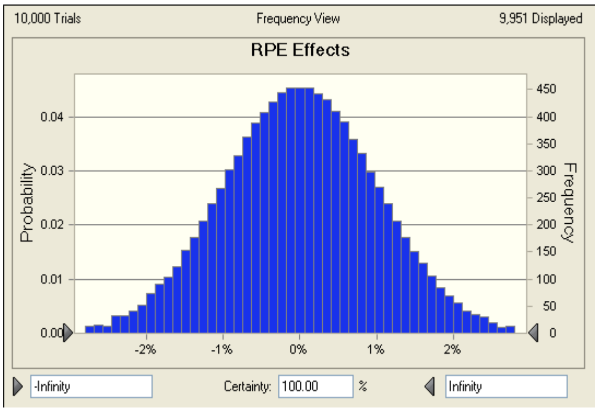
[26] March Strategy Decision Para 4.55

The RAV is adjusted downwards from the forecast values by the customer share of the slow pot saving.

	Forecast values (Overall basis points of RoRE)	Forecast values % of Totex
Trials	10,000	10,000
Mean	1.7	0%
Median	-0.1	0%
Standard Deviation	87.8	6%
Minimum	-321.6	-23%
Maximum	364.2	24%
Range Width	685.7	47%
Mean Std. Error	0.9	0%

Percentile	Forecast values (Overall basis points of RoRE)	Forecast values % of Totex
1%	-195	-14%
99%	214	14%

Real Price Effects



Assumption 11: (% of Totex) Unforeseen Real Price Effects

Normal distribution with parameters:

5% cumulative probability	-2%
95% cumulative probability	2%
Expected Value	0

The impact of Real Price Effects (beyond any allowance) is modelled in the same way as the Efficiency Incentive, but can be adjusted independently as it's assumed to be external and therefore uncorrelated with wider business performance.

A Normal distribution is chosen to reflect unlimited upside/downside tails, with mean 0 and 5th and 95th percentiles at ±2% (so small relative to Totex range). This corresponds to a Standard Deviation of 1%

The effect is symmetric. RPEs are as likely to reduce an overspend as to increase an underspend.

	Forecast values (Overall basis points of RoRE)	Forecast values % of Totex
Trials	10,000	10,000
Mean	0.0	0%
Median	0.0	0%
Standard Deviation	11.4	1%
Minimum	-42.9	-4%
Maximum	42.6	4%
Range Width	85.5	8%
Mean Std. Error	0.1	0%

Percentile	Forecast values	Forecast values

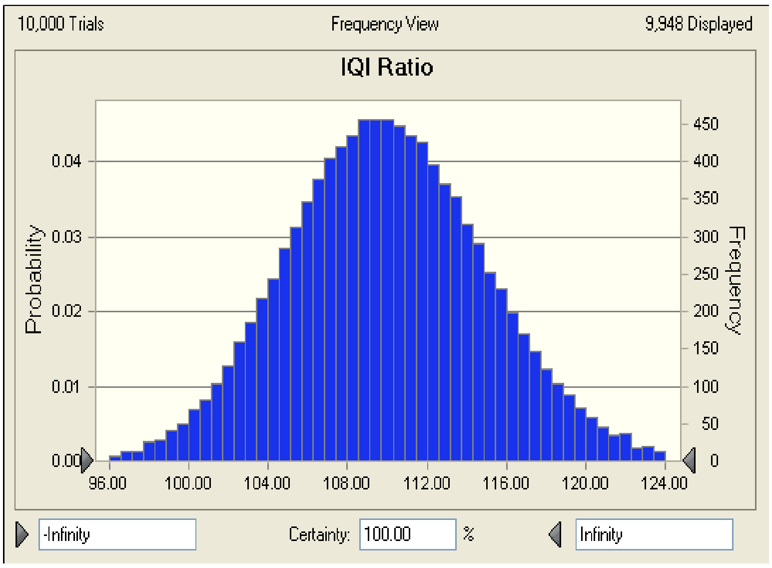
	(Overall basis points of RoRE)	% of Totex
1%	-27	-2%
99%	26	2%

IQI

Assumption 12: IQI Ratio

Lognormal distribution with parameters:

Standard Deviation	6.2
Expected Value	105



The IQI sharing factor and additional income are as derived from the IQI Matrix in Ofgem's Financial Model released on 31st May 2011, with adjustment of the additional income by a constant to set it to zero for an IQI ratio of 100. This results in penalty for all ratios greater than 100.

An IQI ratio of less than 100 is viewed as unlikely based on the historic data available from the DPCR5 cost assessment process. The lower bound of the distribution was chosen to reflect this small probability.

The central position of our distribution at IQI Ratio 105 was chosen to reflect the DPCR5 average. The risk around the midpoint was assumed to be symmetric.

Table 8.1: DPCR5 Final Proposals (excerpt)		
CN West	93%	1.08
CN East	97%	1.03
ENW	91%	1.10
CE NEDL	98%	1.02
CE YEDL	95%	1.05
WPD S Wales	103%	0.97
WPD S West	103%	0.97
EDFE LPN	95%	1.05
EDFE SPN	90%	1.11
EDFE EPN	89%	1.12
SP Distribution	90%	1.11
SP Manweb	93%	1.08
SSE Hydro	100%	1.00
SSE Southern	99%	1.01
Average		**1.050**

We have used a normal distribution to simulate the possible IQI outcomes. The distribution of DPCR5 outcomes is clearly non-normal. A uniform distribution arguably better fits the historic data, but we have chosen to use a normal distribution to reflect the finite (high-impact) risk of extreme divergence between TO and Ofgem's assessments. This is at the cost of overstating the probability of outcomes close to the historic mean.

We note (without explicitly modelling) that there is also uncertainty about deviation from symmetry at the extremes. It might be expected that the probability of a ratio >>100 is materially greater than a ratio <<100, enhancing the downside risk.

	Forecast values	Forecast values

	(Overall basis points of RoRE)	IQI Ratio
Trials	10,000	10,000
Mean	-16.4	105.01
Median	-16.7	104.89
Standard Deviation	20.7	6.24
Minimum	-94.1	83.58
Maximum	64.3	131.12
Range Width	158.4	47.55
Mean Std. Error	0.2	0.06

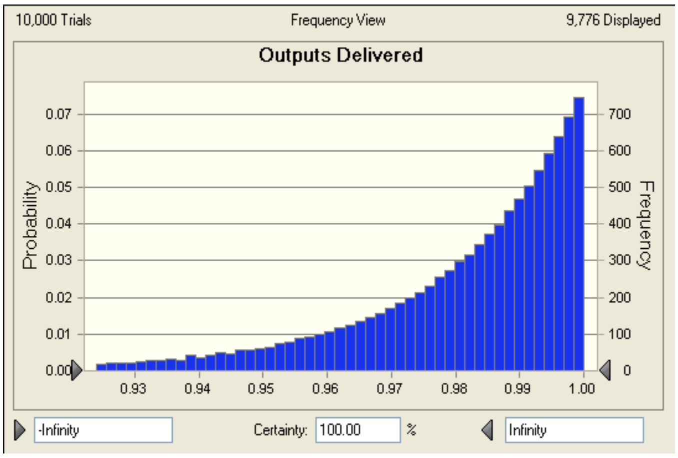
Percentile	Forecast values (Overall basis points of RoRE)	Forecast values IQI Ratio
1%	-64	0.91
99%	33	1.2

Output Penalty

Assumption 13: Outputs Delivered

Exponential distribution with parameters:

Expected Value 98%



We have modelled the incentive on secondary deliverables as penalty only as any reward for over-delivery is conditional on twin hurdles of demonstrating that 1. costs are efficient and 2. that customers positively value the over-delivery. The risk that over-delivery may as a result be unfunded is regarded as high. There is no historical data.

We have chosen a continuous distribution designed to reflect a strong bias towards delivery close to agreed outputs but also to reflect the uncapped downside risk. There is an interaction with Totex Efficiency Incentive.

A penalty for failure to meet secondary outputs is modelled using a normalised unit cost derived on the assumption that allowed RAV additions deliver outputs in full, with full delivery at allowed cost given a score of 100. Delivery of 90% of outputs would score 90, with an output gap valued at 10 * Unit Cost * Output penalty rate

It should be preferable to deliver outputs in full rather than underspend (or refuse to overspend). The Output Penalty Rate is set as a multiple of 1.1*Efficiency Incentive Rate to ensure that there is a marginal incentive to deliver outputs rather than reduce expenditure.

Only expenditure deemed efficient feeds through the Efficiency Incentive. So, for example, expenditure of 95% with delivery of 95% of outputs would not be regarded as an efficient underspend. In such a case there would be a marginal penalty for the 5% missed outputs determined by the difference between the Efficiency and Output incentive sharing factors.

For simplicity secondary outputs have been calculated with reference to Totex rather than exclusively Non-Load expenditure. This simplification is appropriate given the high level of uncertainty as to the precise working of the secondary output adjustment.

	Forecast values (Overall basis points of RoRE)	Forecast values % of Agreed
Trials	10,000	10,000
Mean	-19.2	0.98
Median	-13.3	0.99
Standard Deviation	19.3	0.02
Minimum	-191.5	0.81
Maximum	0.0	1.00
Range Width	191.5	0.19
Mean Std. Error	0.2	0.00

Percentile	Forecast values (Overall basis points of RoRE)	Forecast values % of Agreed
1%	-90	91%
100%	0	100%

Tax Trigger

Assumption 14: Tax Trigger

Modelled as worst/best case: Tax event in year 1
up to max of dead band without triggering.

Bernoulli distribution (with outcomes ±1)
Parameters:

Probability of Tax Rise (-1) 0.75

The impact of the tax trigger deadband is measured as an expected value with a range between defined upper and lower limits.

The upper and lower extremes for the whole price control assume in year 1 a tax event up to the maximum possible within the deadband without triggering (1% increase or decrease in CT rate over any special provision for expected changes). The impact is assumed to persist throughout the price control. On the basis that tax rises at present are judged significantly more probable than cuts, the probability of increase (+1%) = 0.75, cut (-1%) = 0.25.

The value of this event for SPTL is determined by comparing the total base revenue from our version of the Ofgem Financial Model with the total base revenue calculated by the model when the rate of corporation tax is increased in year 1 of the price control and for each year thereafter.

Total Base Revenue £m	2,460.1
Total Base Revenue £m (Tax + 1%)	2,468.3
Difference (% of Base Revenue)	0.335%

Expressed as a percentage of the original base revenue, this is 0.335%.

	Forecast values (Overall basis points of RoRE)
Trials	10,000
Mean	-4.4
Median	-8.8
Standard	7.6
Minimum	-8.8
Maximum	8.8
Range Width	17.5
Mean Std. Error	0.1

Percentile	Forecast values (Overall basis points of RoRE)
0%	-9
100%	9

Aggregated Risk of Package

Monte Carlo simulation has been used to identify the limits of the overall return distribution (simulating all risk components together, rather than one by one) as an alternative measure of the total RoRE risk.

Any implicit assumption that incentive performance is uncorrelated between components (simulating all components together with no correlation imposed) is likely to understate the overall risk. The precise correlation between components is unknown, but likely to be material.

Further, as many of the risk components are likely to contain both systemic and random elements, the correlation may well strengthen towards the extremes of outcome.

For these reasons a RoRE range obtained by modelling the aggregated risk with an assumption of moderate correlation is best regarded as indicating an absolute minimum of plausible RoRE risk. Greater weighting should attach to the range identified by the 'Layer Cake'.

The incentives in the table below are assumed to be moderately correlated, with correlation coefficients as shown[27]. Other coefficients and outputs are assumed to be uncorrelated.

Correlation Matrix	Customer Survey	Stakeholder	Connections	Planned outages downside	Planned outages upside	Wider Works	Output Shortfall	Totex efficiency
Customer Survey	1.0	0.5	-0.5	-0.5	0.5	-0.5	-0.5	-0.5
Stakeholder		1.0	-0.5	-0.5	0.5	-0.5	-0.5	-0.5
Connections			1.0	0.5	-0.5	0.5	0.5	0.5
Planned outages				1.0	-0.5	0.5	0.5	0.5
Planned outages					1.0	-0.5	-0.5	-0.5
Wider Works						1.0	0.5	0.5
Output Shortfall							1.0	0.5
Totex efficiency								1.0

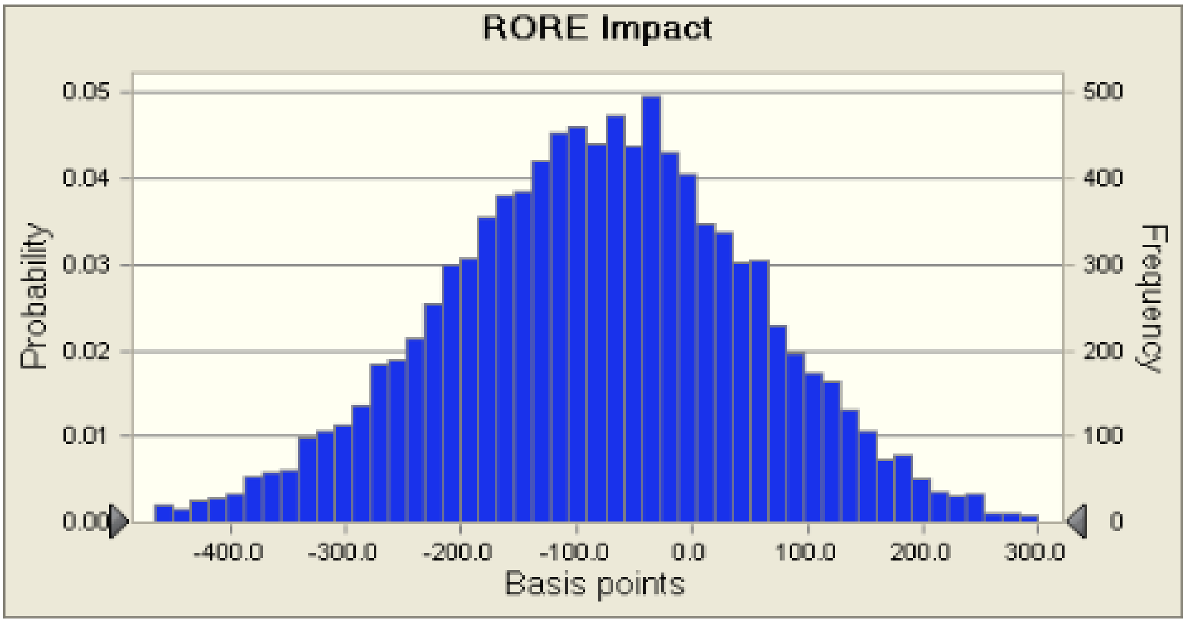
[27] Sign conventions dictated by operation of the model – some may be counter-intuitive as tabulated.

There is (additional to any broader risk correlation) a deterministic interaction between the IQI, Totex Efficiency Incentive, Outputs and Unplanned Outages via the IQI Sharing Factor.

The aggregate impact of the risks (with correlation applied where appropriate) is tabulated below:

Aggregate of Risks (with correlation)	Forecast values
Trials	10,000
Mean	-83.2
Median	-79.5
Standard Deviation	136.7
Minimum	-619.1
Maximum	452.8
Range Width	1071.9
Mean Std. Error	1.4

Aggregate of Risks (with correlation):- Percentile	Forecast values (Basis Points of RoRE)
0%	-619.1
1%	-418.5
2.5%	-361.0
5%	-314.3
50%	-79.5
95%	136.9
97.5%	178.2
99%	229.2
100%	452.8



9.6 Financial Results – Including Risks & Incentives

Summary Statutory Financial Statements

The following tables show the forecast statutory financial position of SP Transmission after reflecting the impact of the incentive mechanisms.

P&L (£m Nominal)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Turnover	279	321	361	393	417	440	463	487
Operating profit	197	225	253	282	292	316	330	347
Interest	-56	-69	-83	-92	-91	-99	-105	-107
Tax	-34	-36	-39	-44	-46	-50	-52	-55
Dividend	-42	-51	-60	-62	-73	-75	-79	-81
Retained profit	65	69	71	84	82	92	94	104

Cash flow (£m Nominal)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Operating cash flow	242	271	297	332	354	382	401	412
Tax paid	-14	-14	-14	-16	-18	-20	-23	-26
Capital Expenditure	-417	-471	-384	-287	-293	-301	-290	-153
Interest & Dividend	-98	-120	-143	-154	-164	-174	-184	-188
Cash flow before financing	-287	-334	-244	-125	-121	-113	-96	45
Equity Issue	112	144	0	143	0	0	0	0
(Increase)/Decrease in Debt	-175	-190	-244	18	-121	-113	-96	45

Balance Sheet (£m Nominal)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Fixed Assets	1533	1916	2347	2682	2914	3147	3383	3603	3680
Working capital & Tax	-87	-99	-104	-99	-96	-99	-101	-103	-95

Debt	-739	-914	-1104	-1348	-1330	-1451	-1564	-1660	-1615
Deferred Tax	-138	-157	-180	-205	-231	-258	-287	-315	-341
Net assets	569	746	959	1030	1257	1339	1431	1525	1629

Regulatory Asset Value

Regulatory asset value increases by £1,674m to £3,160m.

Closing RAV is shown in the following table

Closing RAV (£m Nominal)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Closing RAV	1486	1828	2208	2489	2660	2828	2997	3150	3160

Financeability

The target financial ratios for assessing our financeability are set out in the table below. We have targeted A/A- in our base position before considering the impact of incentive mechanisms. Ratios are discussed further in section 9.2. Moody's regard Net Debt/RAV and PMICR as the most important ratios (they attribute a weighting of three times more importance to these two ratios than the others). The Net Debt/RAV and PMICR ratios are those used by the Competition Commission in their report on Bristol Water in 2010. The other three target ratios have been extrapolated from the ratios quoted in the March 2011 Strategy decision paper (Financial Issues paper paragraph 4.9).

Target credit ratios	Range at A-
FFO interest cover (x)	3.0 – 4.0
Net Debt / RAV (%)	60 -68
FFO/ Net Debt (%)	10 – 16
PMICR using RAV depreciation (x)	1.8 – 2.5
RCF / Capex (x)	1.5 – 2.0

The financial ratios that result from our plan are shown in the following table.

Financeability ratios	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Average
FFO interest cover (x)	4.0	3.7	3.4	3.5	3.7	3.7	3.6	3.6	3.6
Net Debt / RAV (%)	50.0	50.0	54.2	50.0	51.3	52.2	52.7	51.1	51.4
FFO/ Net Debt (%)	24.9	23.3	21.0	23.8	23.1	23.2	22.8	23.9	23.3
PMICR using RAV depreciation (x)	1.9	1.7	1.5	1.5	1.6	1.6	1.6	1.5	1.6
RCF / Capex (x)	0.3	0.3	0.4	0.6	0.6	0.6	0.7	1.3	0.6
Regulated Equity/EBITDA	4.0	4.2	3.8	3.9	3.9	3.8	3.7	3.7	3.9
Regulated Equity/Earnings	3.3	3.4	3.2	3.4	3.3	3.3	3.2	3.2	3.3

The first three ratios comfortably meet or exceed the A/A- targets. PMICR is below the A- target for all years except 2013/14. RCF/Capex is significantly below the A- target. However, Moody's believe that utilities undergoing a large capex programme who do not benefit from accelerated depreciation are expected to score this metric in the range 0.5 – 1.0 (March 2001 Strategy decision paper Financial Issues paper notes to figure 4.1); but in 2013/14 to 2015/16 the ratios are still below this lower threshold.

We have also included Regulated Equity / EBITDA and Regulated Equity / Earnings as they were quoted in Ofgem's strategy decision paper; however we have no clear view of target thresholds.

Overall we consider that these ratios provide only borderline investment grade quality after all risks and incentives are taken into account.