RIIO-ED1: Managing volatility

A report for EDF Energy

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1. INTRODUCTION

1.1. Context

The cost of distributing electricity from the transmission system to users is around 18 per cent of an average domestic customer's bill and potentially a similar proportion for smaller non-domestic customer bills. This means that the level of revenues recovered by the 14 distribution network operators (DNOs), and how these revenues are recovered through final consumers energy deals, can have a material financial impact on households, businesses and other final users of electricity.

As well as the level of distribution use of system (DUoS) charges, an equally important issue for suppliers, consumers and DNOs, is the profile, volatility and predictability of DUoS charges. This can affect their planning, expenditure and financing decisions, and in the case of the DNOs, also the ability to finance their businesses. It also affects the costs which suppliers must recover from their customers.

However, the building blocks of cost reflective DUoS charges can never be known with certainty. Indeed, the DNOs' expenditure in their networks can change as the outputs and the requirements of their businesses change. Tariffs (as opposed to revenues) are also affected by use of the electricity distribution system since the DNOs are currently allowed to recover regulated revenues largely regardless of the actual demand for network access.

Projected changes in network costs, and the uncertainty of future costs, can be reflected in DNOs revenue allowances, and therefore tariffs, at the time of the price control review. Alternatively, changes in costs and revenues can be managed by way of adjustments to tariffs applied *within* the period of the price control (for example, indexation of allowed revenues to the RPI, changes due to losses incentive adjustments or adjustments to allowed pass-through costs, such as business rates).

1.2. Managing volatility and unpredictability

Currently it is final consumers and suppliers who are tasked with forecasting changes in revenues, demand and DUoS tariffs, whether within or between price controls, and managing the risks, and the cost of risk, from any volatility and unpredictability of DUoS charges.

This is because, with the exception of any profiling of DNO revenues at the time of the price control review and a lag in adjustments such as incentive payments, allowed changes in the DNOs revenues and tariffs are passed through into network user charges. This occurs from one financial and charging year to the next, both between and within price control settlements.

Where full network cost pass-through to final consumers can be achieved (which is not always the case given the fixed price deals offered by suppliers, and the differences in the structure of charges for networks and final retail tariffs), the consumer must manage the change in cash-flow through expenditure or borrowing. In theory this creates little additional cost for consumers. However, in reality certain end consumer groups (domestic and non-domestic) may incur a very high cost of accessing the funds for the payment of unexpected changes in their energy bills.

Where it is electricity suppliers who have to manage DUoS price volatility, either from a temporal mismatch in cost recovery of network costs from their customers, or because the final consumer chooses to enter a fixed price contract, they are likely to charge a premium to cover the costs of managing the lack of predictability and volatility of their charges, either explicitly or through the specific profit margin they are willing to accept for a customer contract.

Whoever manages the cash-flow risk, there is a real financial cost from volatile and unpredictable DUoS charges, a cost of risk, not always recognised within the industry. Partly this is because costs are implicitly rather than explicitly reflected through the pricing arrangements for final retail contracts, and so the impacts are not fully costed.

However, for these arrangements to be an efficient allocation of risk, and resulting cost of risk borne by the final consumer, assumes that:

- consumers and suppliers are the stakeholder groups best placed to manage volatility and unpredictability of network charges;
- the opportunity cost of funds to manage the cash-flow risk from network charges is lower for consumers and suppliers than the DNOs;[1] and
- DNOs future charges are sufficiently predictable that it is proportionate for consumers and suppliers to seek to manage future volatility and unpredictability.

These issues form part of wider policy questions of how network costs, and other standardised elements of the final bill, should be managed through efficient retail pricing structures. This includes Ofgem's reforms proposed through the Retail Market Review (RMR) to:

- reduce retail pricing complexity through introduction of more standardised and transparent pricing structures;
- introduce methodologies that may actually set the standardised element of the bill, for which network costs are a key component; and
- facilitate fixed price contracts, additional to standard evergreen products, that would support consumer engagement in the market and more effective competition.

This suggests that managing the cash-flow risk resulting from the inherent unpredictability and volatility of network charges is an important part of:

- enhancing competition in Great Britain's (GB) retail energy markets and making the market work more effectively;
- helping to promote more transparent and less complex pricing arrangements (both for networks and retail energy supply); and

[1] Here it is important to draw a distinction between planned and unplanned funds.

- achieving the overall regulatory objective of delivering to final customers, a sustainable service, that allows DNOs and other stakeholder groups to invest efficiently in their businesses, at as low a cost as possible.

1.3. Purpose

This report, provided by CEPA on behalf of EDF Energy, considers the economic principles of managing network pricing volatility including the future profile and the predictability of DUoS charges. We have been asked to consider alternative approaches to the current arrangements of managing network charging volatility and unpredictability, building on the proposals already made by Ofgem through its work on mitigating network charging volatility.

Overall our conclusions are that:

- current arrangements for managing the cash-flow risk from DUoS charges may not lead to the most efficient allocation of risk, and therefore cost of risk;
- the options we have evaluated could provide greater certainty of future DUoS charges and a more efficient allocation of risk; and
- there are potential benefits for a range of industry stakeholder groups, including suppliers, DNOs and final consumers from these proposals.

Our cost benefit analysis suggests that:

- the benefits (in terms of competition impacts and reduced supply costs) could exceed any costs that might be incurred by the DNOs from the options evaluated;
- this result is robust to different assumptions and scenarios that have been explored through our cost benefit model; and
- these options would address the issue of network charging volatility and unpredictability within *and* between price control periods.

The volatility and predictability of DNO's future DUoS charges (and network charges more generally) has been an important issue for a while now.

Given the wider context and changes in retail energy markets and regulatory policy (in particular Ofgem's proposals under the RMR) the interventions we have considered to provide more predictability and less volatile network charges, would provide relatively simple, cost effective solutions for addressing the issues.

We believe this to be an important topic that should be consulted on through a stakeholder driven network price review process.

1.4. Document structure

The sections which follow consider:

- evidence and analysis of the drivers of DUoS charging unpredictability in the electricity distribution sector both historically and looking forward to RIIO-ED1 (Section 2);
- how managing DUoS charging unpredictability imposes a cost on the electricity industry and ultimately final consumers (Section 2 and 3);
- how the opportunity cost of accessing funds to manage cash-flow risk from unpredictable charges differs across industry stakeholder groups (Section 3);
- options for how unpredictable and volatile DUoS charges can be managed including a brief review of Ofgem's proposals (Section 4);
- our quantitative and qualitative impact assessment, including the costs and benefits, incentive effects and competition impacts, of different options (Section 5); and
- conclusions and proposed next steps for how possible new arrangements could be implemented through RIIO-ED1 (Section 6).

2. BACKGROUND AND CONTEXT

This section considers:

- historical evidence and drivers of charging volatility in the electricity distribution sector;
- how this volatility is managed under current industry arrangements;
- Ofgem's proposals for the RMR; and
- the context to RIIO-ED1.

2.1. Charging volatility

As noted by Ofgem in their recent consultation paper on network charging volatility there are a number of factors which can lead to the DNOs actual allowed revenues diverging from the base revenue allowed at the price control review. The table below (sourced from Ofgem's consultation document) presents the percentage contribution of each factor to this difference between the allowed revenues and base revenue, as an average for all DNOs from 2005/06 to 2010/11.

Table 2.1: Contribution to volatility in allowed revenues[2]

	Electricity Distribution	
	Average decrease	**Average increase**
Inflation	-0.4%	3.5%
Pass through costs	-1.4%	1.1%
Incentives	-2.9%	4.1%
Uncertain costs	-0.1%	0.1%
Innovation funding	0.0%	0.3%
Other	0.0%	0.0%
Carry over from previous year	-2.4%	4.4%
Total difference[3]	-4.7%	9.4%

Source: Ofgem

Volatility in final *tariffs* can be caused by the volatility in final allowed revenues (as highlighted above) but also from changes in network access and use (demand) which can also vary on an annual basis. The DNOs regulatory regime is a revenue cap, and as a consequence the tariffs that network users pay (to recover allowed revenue) will vary according to demand. This adds an additional source of volatility that needs to be managed.

[2] Ofgem 'Mitigating network charging volatility arising from the price control settlement' , 13th April 2012.
[3] Represents the average decrease (and increase) across all financial years where allowed revenue was lower (higher) than the base revenue. The average of positive and negative adjustments is shown separately.

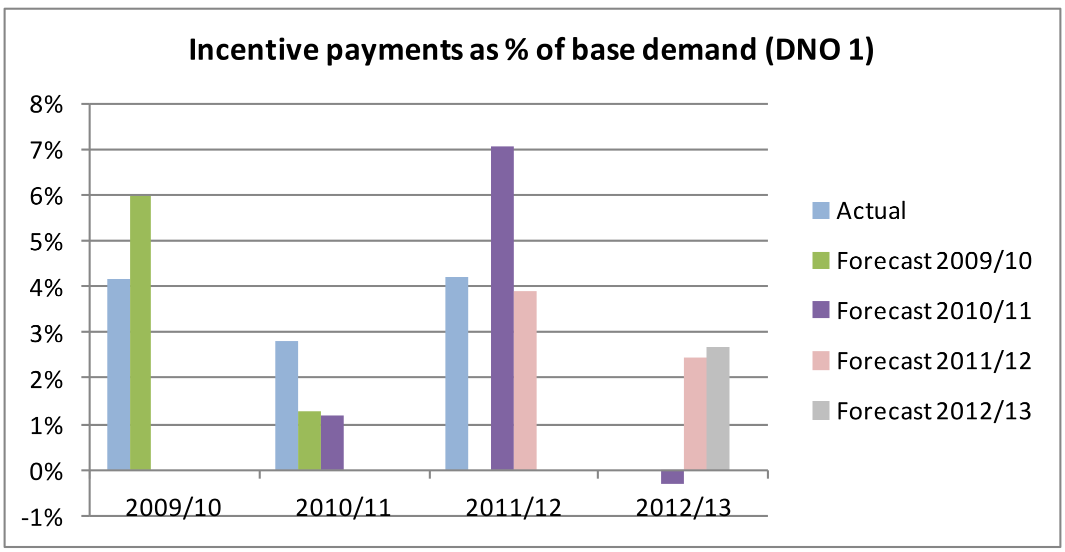
2.2. Charging predictability

Analysis of the revenue reporting data provided by the DNOs (under clause 35A of the Distribution Connection and Use of System Agreement (DCUSA)) shows that volatility in the factors set out in Table 2.1 can also lead to significant forecasting errors in the allowed revenue adjustments made by the DNOs. This acts to reduce the predictability of DUoS charges for network users.

The DNOs report and calculate their final allowed revenues as follows: final allowed revenue = base demand revenue (as included in the licence) forecast after inflation + allowed pass through costs + incentive payments and other adjustments + correction factor. This terminology is used in the analysis of DNO revenue reporting below.

Figures 2.1 and 2.2 show the volatility in incentive revenue and other related adjustments for two DNOs and the resulting volatility in their forecast values for allowed revenue.[4] The blue bar shows the actual incentive revenues as a percentage of base demand revenue whereas the other lines show the forecast for this ratio in years preceding this. Both illustrations show that the DNOs have over and under forecast allowed future incentive revenues, with forecasts varying year by year.

Figure 2.1: DNO incentive payment volatility [5]



Source: CEPA analysis of DCP066 reports

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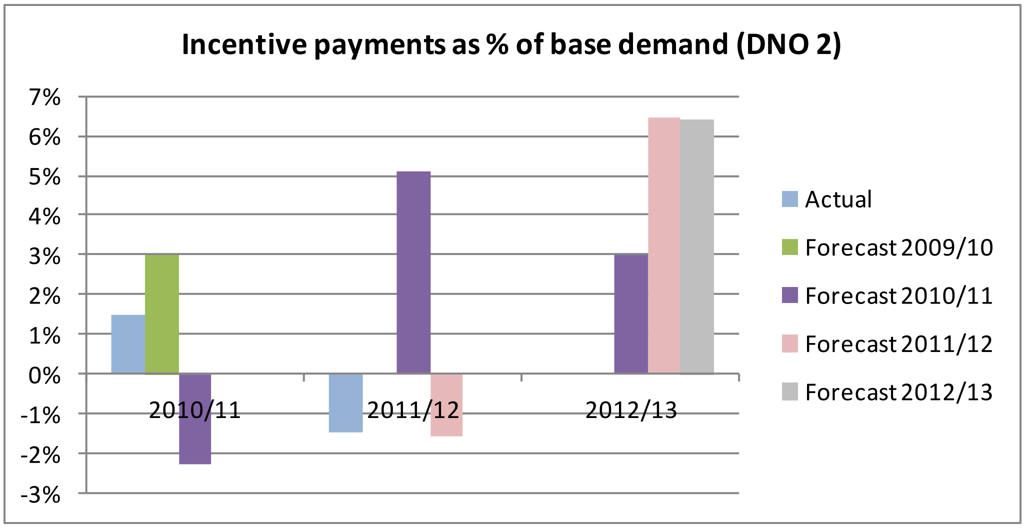
[4] The latest forecast in each year was used for the figures.

[5] The blue bar shows the actual incentive revenues as a percentage of base demand revenue whereas the other lines show the forecast for this ratio in that year for the years preceding this.

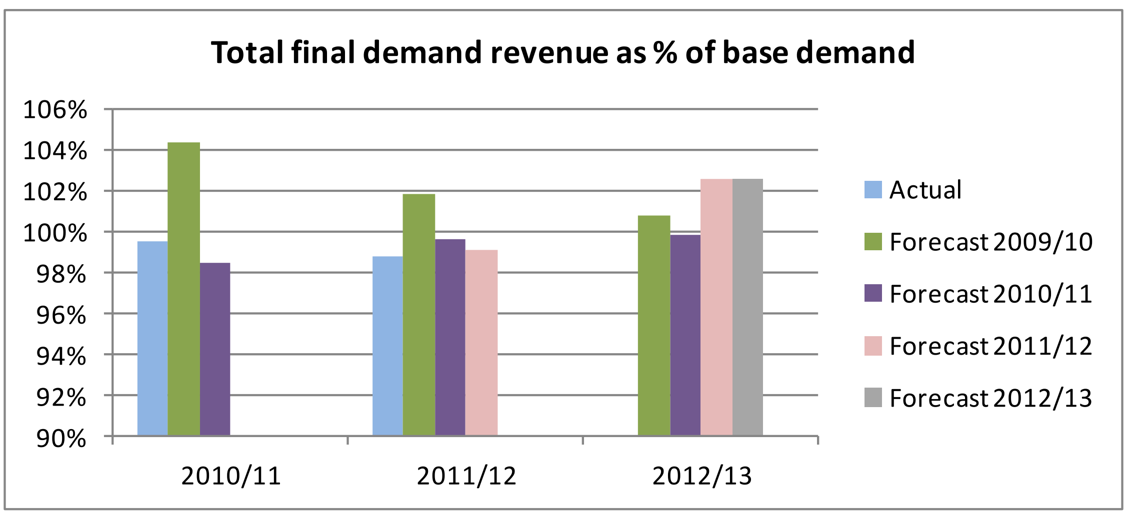
Figure 2.2: DNO incentive payment volatility [6]



Source: CEPA analysis of DCP066 reports

Looking at the impact of allowed revenue adjustments across the DNOs on average (Figure 2.3) we get a more general picture of the movements in forecast and actual level of final total demand revenue as a percentage of the base demand over the DPCR5 period. Interestingly in 2010/11 actual final allowed revenue was above the latest forecast, whereas in 2011/12 actual figure was below the latest forecast. What is clear from this analysis is that the forecasts improve as we approach the actual year, however their predictability two to three years in advance is currently relatively poor.

Figure 2.3: Average across all 14 DNOs



Source: CEPA analysis of DCP066 reports

[6] The blue bar shows the actual incentive revenues as a percentage of base demand revenue whereas the other lines show the forecast for this ratio in that year for the years preceding this.

Table 2.2 shows the path of base demand revenue for a subset of DNOs as allowed at the time of the DCPR5 final determination. Ofgem proposed to profile allowed revenue increases in order to achieve a constant percentage increase each year over the 2010 to 2015 period. Without having detrimental financeability impacts on the DNOs, this was considered to be the best option for consumers, since it protected them from a sudden increase in their distribution charges.

Table 2.2: Profile of DNO base allowed revenue (£m 2007/08 prices)

Distribution service area	**DCPR4**	**DPCR5**	**Change from DPCR4 to DCPR5**	**Average annual X**
CE NEDL	885.6	1,187.2	34.1%	7.7%
CE YEDL	1,156.8	1,521.0	31.5%	6.5%
EPN	1,652.8	2,121.6	28.4%	5.5%
LPN	1,294.3	1,752.2	35.4%	7.1%
SPN	967.6	1,422.1	47.0%	8.8%
ENW	1,265.5	1,813.2	43.3%	8.5%
SSE Southern	1,923.3	2,323.0	20.8%	3.9%
WPD S Wales	829.2	1,046.7	26.2%	6.2%
WPD West	1,016.3	1,355.1	33.3%	7.5%
Total	**17,363.3**	**22,192.1**	**27.8%**	**5.6%**

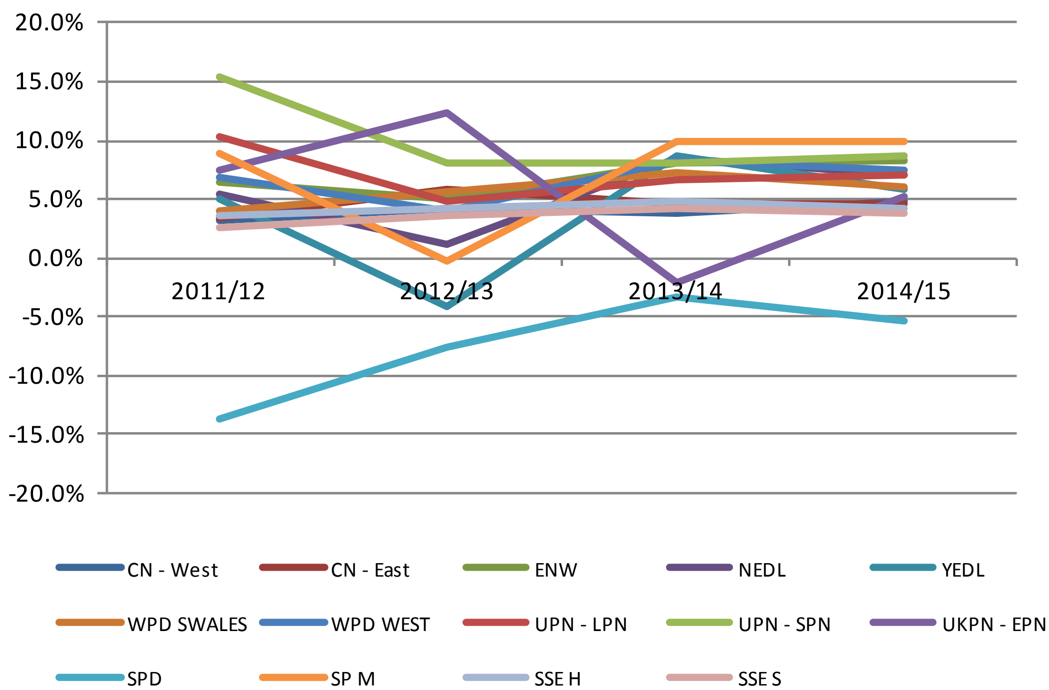
Source: Ofgem

However, while the issue of revenue profiling was proposed through the DPCR5 initial proposals, it was only at the final decision paper (c. 4 months before the DUoS charges took effect) that this information was made available to the market for the pricing of retail contracts. Furthermore, having reviewed the actual base allowed revenues included in the final licence conditions it is not clear that Ofgem actually applied this policy in practice. Figure 2.4 (overleaf) shows the actual year on year movements in base demand revenue included in final DNO licence conditions[7]

As discussed above, network demand also adds an additional source of volatility to final DUoS tariffs. This creates further unpredictability for suppliers and end-consumers having to forecast their future network charges. Although suppliers who operate within the market are likely to have early access to information on changes in demand, even the largest players are likely to have less than perfect information of demand by distribution area. Smaller, more niche, suppliers to non-domestic sector, are likely to be particularly disadvantaged. The implication is that network demand is a source of unpredictability as well volatility for DUoS charges.

[7] The accompanying letter for the statutory consultation on the licence modifications notes that "*In response to representations from several DNOs we have revised an element of the profiling treatment of PU* [Base Revenue] *values … we have excluded revenue adjustments for historic ESQCR and TMA factors from profiling to ensure consistency with the terms of the Authority's earlier decisions on these matters. The revised treatment means that allowances for most DNOs are slightly higher in the earlier years of the price control period and correspondingly lower in the latter years when compared to those in the price control proposals that were published on 7 December 2009. However, the revised profiling treatment has not changed the total net present value of the allowances.*"

Figure 2.4: Profile of DNO base allowed revenue (2010/11 prices



Source: Ofgem – Appendix 1 of Condition 3.6

2.3. How is charging volatility and unpredictability managed?

2.3.1. Risk allocation

As discussed in the introduction, currently the risk of managing network charging volatility and unpredictability largely rests with the supplier and end consumer. This is because the DNOs recover their actual incurred network charges in each period, however suppliers use forecast network charges to make pricing decisions for future fixed price contracts.

If those forecasts happen to be lower than the actual future network charges, they stand to incur a loss which often cannot be passed on to future consumers due to the competitive nature of the retail market.[8] On the other hand, if those forecasts are higher than the actual future network charges, then the customer stands to lose out (see discussion below).

If volatility in network charges could be passed straight on to the final consumers, then there would be no additional cost of managing the uncertainty for suppliers within or between the price controls. However as illustrated by Figures 2.1, 2.2 and 2.3 above, the predictability of future network charges

[8] We are aware that in the non-domestic sector there are fixed and variable price contracts that do allow for full cost pass-through of network costs from the supplier to the end-consumer.

can be low, either because of inter or intra-price control revenue volatility, or because of changes in other aspects that feed into the DNOs final charging statements (for example, network demand).

The predictability of future network charges can be particularly low around the time of the price control review. Figure 2.5 shows the DNOs current forecasts for base allowed revenue (i.e. before revenue adjustments) as published through DCUSA reporting processes. It shows a business as usual, or no change scenario, for 2015/16 with no indication of (any) possible P_0 adjustment (indeed, a number of DNOs currently forecast a small decrease in their allowed revenues).

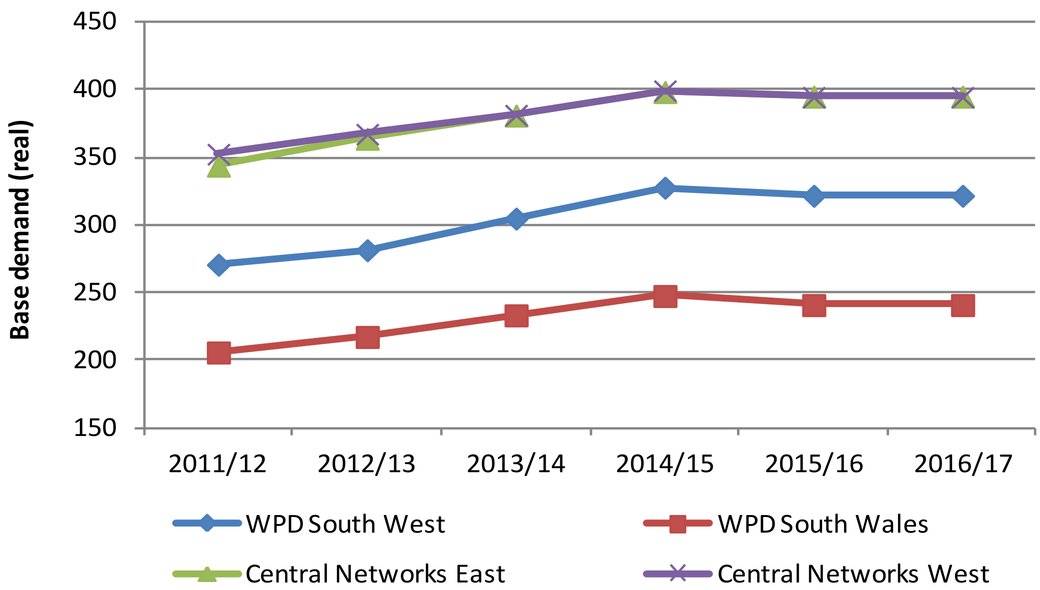
From the consumer's point of view, many of them engage in consumption budgeting and hence have a preference for fixed energy contracts. This preference of course shifts depending upon the state of the energy market. For example, if the customer foresees a rise in future energy prices their preference for hedging against this risk by buying a fixed term contract will increase. The point is that fixed term contracts are an important tool for those customers who are liquidity constrained, risk averse, or potentially more vulnerable than customers on variable contracts.

In the domestic market, the majority of consumers are on variable price contracts. However, consumers are increasingly electing to take up fixed price contracts, due to the benefits these bring in terms of greater peace of mind and certainty on costs in view of wholesale price variability. We estimate that approximately 15-25% of the market is made up of fixed price contracts. These contracts are usually fixed for 1-2 years.

In the non-domestic market, most customers are on fixed price contracts, representing perhaps half of the total volume, as larger companies are more likely to have flexible contracts. Smaller customers with more simple requirements will typically be looking to fix their costs, perhaps for 1-2 years, whereas heavier electricity users with dedicated energy professionals or advisers typically require contracts with variations on pass-through arrangements, and some of the largest contracts could be for 2-3 years. Contracts in this sector tend to arranged on a bespoke basis.

If the predictability of network costs is low, the network cost component of fixed term and fixed price contracts are particularly risky for suppliers and end consumers. This results in risk premia or cost of risk that arises from the risk allocation.

Figure 2.5: Profile of DNO base allowed revenue (2007/08 prices)



Source: CEPA analysis of DCP066 reports

2.3.2. Risk premia

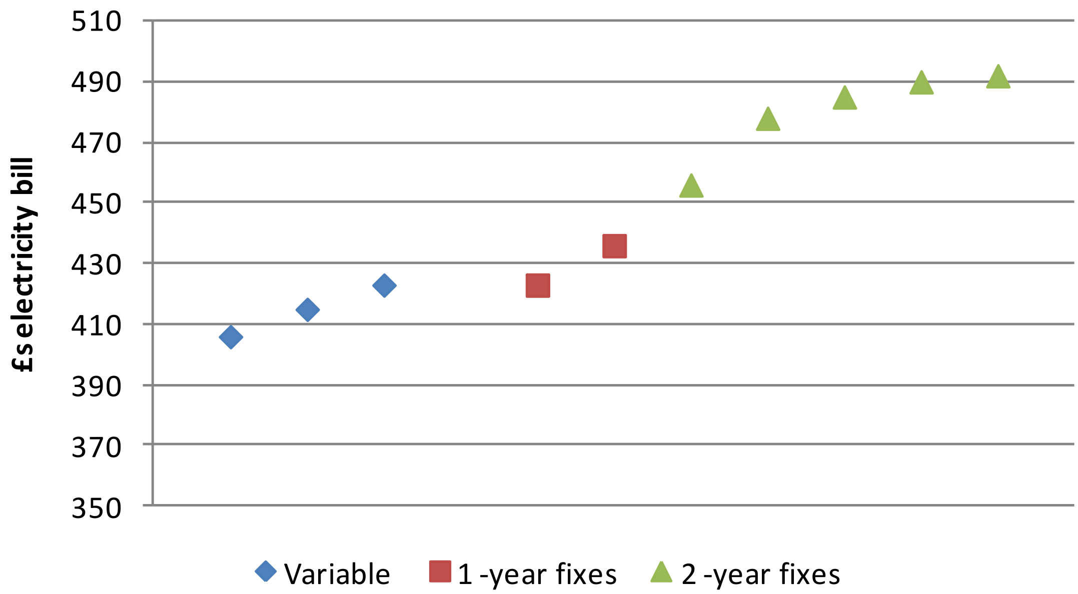
For the supplier, the risk of charging a future price below their future network marginal cost (including the costs of generation, transmission and distribution) thereby incurring a loss, or a reduction in their margins, is very real since a reduction on already tight margins is unlikely to be recoverable at a future date. While there are various tools to help them manage this risk, in the case of distribution costs, these still place the risk of forecasting DUoS charges on the supplier.

How do suppliers manage this risk?

Two possible ways for suppliers to manage risks are an explicit insurance premium on fixed price contracts, or the supplier accepting a loss or a lower contract margin. Hence when making the pricing decision, the supplier faces a trade-off between charging a high premium to fixed contract customers to hedge against future volatile network charges and charging a low risk premium to gain or retain customers. The materiality of the risk is dependent on the supplier's portfolio of customers (e.g. domestic vs. non-domestic), exposure to fixed price energy deals as well as appetite for risk.

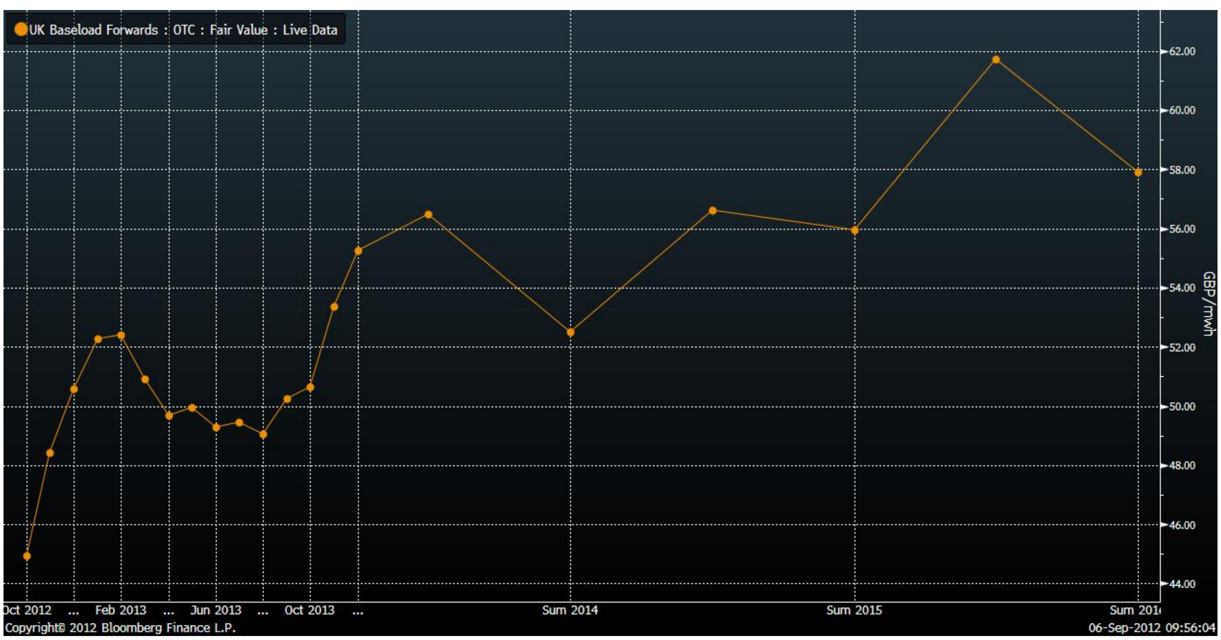
This is illustrated through Figure 2.6 which shows the "forward" curve for fixed price contracts of different durations currently available in the market. While the upward sloping nature of the curve partly reflects the forward curve for wholesale prices (shown in Figure 2.7 (overleaf) for current UK Baseload forwards) it also reflects the cost of risk for elements such as network charges. This is reflected in the actual prices consumers pay for fixed or capped retail energy deals.

Figure 2.6: Annual retail electricity domestic spend duration curve



Source: CEPA analysis of Guardian data (based on a London address and medium flat residence)

Figure 2.7: UK Baseload Forwards



Source: Bloomberg

An alternative way to look at the cost of charging unpredictability issue is illustrated through Figures 2.1, 2.2 and 2.3. If suppliers were to adopt the DNOs forecasts of future allowed revenue to produce their DUoS tariff projections, both for fixed price and more variable contracts, in cases where DNOs have over-forecast their allowed revenues, the result would have been that consumers would have to pay more than the actual DUoS charges based on final allowed revenue. In this scenario the end consumer is left even worse off from the unpredictability of the DNOs tariffs.

2.3.3. Conclusions

The crux of the problem is that it is the customer who potentially loses out due to the natural forecasting errors made by the suppliers, or approaches to margin management taken by suppliers to account for these expected errors, when pricing fixed term and even aspects of variable contracts (depending on the precise type of contract in place). Irrespective of whether the underlying network charges were under or over forecast the inbuilt risk premium means that the final price offered to consumers is above what would have been offered in the absence of the risk. Moreover, if the forecast made by the suppliers turns out to be above the actual network charges, then customers stand to lose out even more.

2.4. Ofgem's RMR proposals

One of the key reforms proposed under the RMR is the introduction of standardised tariff elements to address complexity of tariff information provided by suppliers. RMR proposals would:

- restrict the number of tariffs for standard evergreen products from each supplier to only one per payment method (direct debit, standard credit and prepayment meters);
- structure all standard tariffs to consist of a compulsory regional standing charge and a national unit rate set by suppliers (day / night rates for Economy 7 tariffs); and
- possibly introduce a regional adjuster to the unit rate to account for regional differences in network costs that vary by consumption.

Under current proposals[9], Ofgem would set the regional standing charge and the possible compulsory regional adjuster to standard unit rates.

The RMR seeks to increase competition in the retail supply market by making the tariffs simpler to understand for the consumer. Ofgem's proposals are also pushing fixed price contracts as a way for suppliers to compete outside of the standard evergreen tariff. This would mean the capacity to offer and manage risks associated with fixed price deals would continue to be an important, indeed more significant, part of enhancing competition in GB retail energy markets, including the goal of making the market work more effectively.

Ofgem's updated RMR proposals are now expected before Winter 2012.

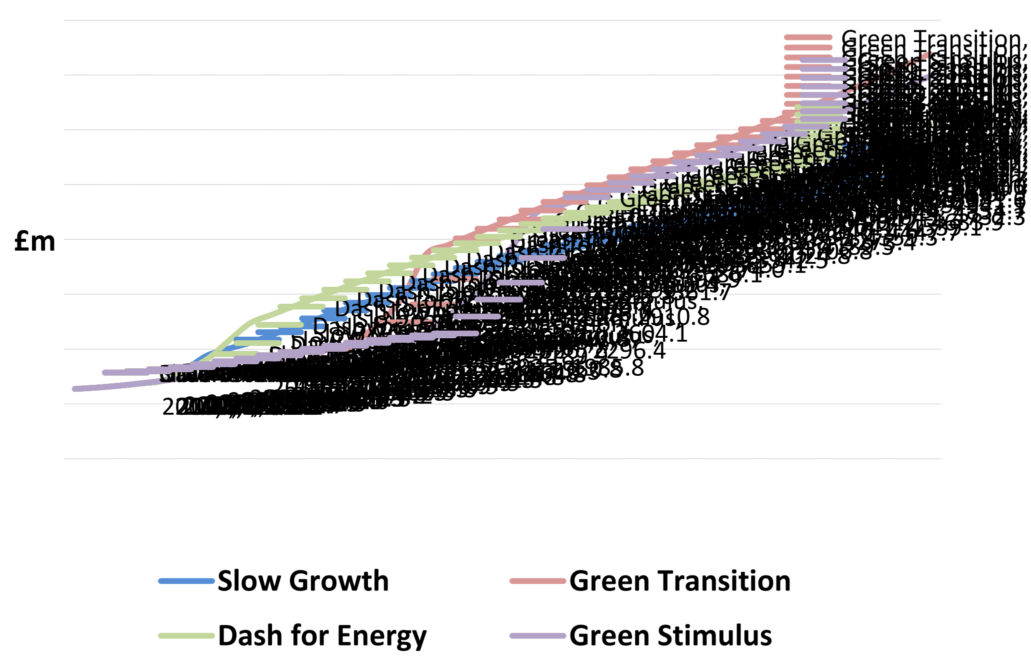
[9] Retail Market Review Consultation, Ofgem, December 2011.

2.5. RIIO-ED1

The next electricity distribution price control is due to start on the 1st April 2015 and will be the first electricity distribution price control review to reflect the new regulatory framework, known as the RIIO model (Revenue = Incentives + Innovation + Outputs). Significant capital expenditure may be required by the DNOs during RIIO-ED1 to support the transition to the low carbon economy and to decarbonise heat and transport.

The new regulatory regime to be implemented under RIIO-ED1 also poses new challenges for uncertainty issues for the suppliers and consumers. The focus on low carbon and more sustainable forms of energy production will entail higher investment by the electricity distribution industry and a higher capex requirement. However, (as illustrated in Figure 2.8 taken from CEPA's report on Economic Asset Lives of Energy Networks for Ofgem)[10] there is still significant uncertainty around future capex requirements, and this can be expected to affect the DNOs business plans which in turn will feed into the forthcoming price controls. For example, uncertainty over the pace and impacts of major programmes such as smart metering and development of smart grids.

Figure 2.8: Annual capex for the electricity distribution network, by scenario



Source: CEPA

Currently suppliers and consumers (through the arrangements described above) are exposed to the possibility of a price shock between the current price control settlement and RIIO-ED1, due to:

- possible regime changes;

[10] CEPA (2010): 'The Economic Lives of Energy Network Assets: A report for Ofgem' available here.

- changes in network outputs; and
- a possible ramp up in DNO's expenditure requirements.

Based on past price review processes, this creates a change in charges that will only be known with any certainty three months before the start of the next period.

One of the important changes under RIIO is also a move away from five year price controls to eight year price controls. Eight year price controls will include a limited window ("re-opener") after four years to review the price controls focused on the outputs delivered by the network companies. The mid-period output review introduces an additional source of uncertainty to the DUoS charge setting process, potentially creating two pricing 'cliff-edges' rather than one, and hence higher cash-flow risk borne by suppliers and end- consumers from forecasting these changes.

2.6. Summary

This section has set out the background and context of the historical drivers of DUoS charging unpredictability and volatility. Looking forward, it also has shown how this issue is linked to wider policy reforms in the energy sector, in particular Ofgem's current proposals for the RMR, and how future volatility is linked to the uncertainty around future DNO expenditure requirements and the design of the RIIO control. We now turn to the key issues which need to be considered for efficient allocation of network pricing volatility and risk.

3. Key issues

This section considers the economic principles which drive and underpin the issue of how to manage volatility of cost reflective network charges. We also set out the core objectives and criteria that any reform options should seek to achieve.

3.1. Principles

Ofgem's consultation on mitigating network charging volatility correctly highlights that the key issue when evaluating the options for addressing and mitigating network charging volatility is who is best placed to manage this cash-flow risk, and the financial cost of that risk. This risk allocation question can be considered from the perspective of:

- the **information** available to different industry stakeholder groups to support their management of the cash-flow risk;
- the **ability (or elasticity)** for stakeholder groups to manage cash-flow risk by responding to pricing volatility; and
- the **cost of risk** i.e. who has the lowest (opportunity) cost of funds for managing changes in cash-flows from unpredictable and volatile charges.

3.1.1. Information

As regards information, during the time of the price review (as currently for RIIO-ED1) while there is uncertainty of the final revenue allowances, which are ultimately determined by the Gas and Electricity Market Authority, it is the DNOs that have the earliest sight of their price control business plans and future network expenditure requirements.

For networks costs, revenue adjustments and tariff changes within the price control, again the stakeholder group with the best access to information is the DNOs. This reflects the principle of a cost reflective DUoS tariff. DNOs are already required to forecast their required and allowed revenue through their DUoS charging statements and invoicing.

However, while published informational tools, such as DNO forecasts of allowed revenue (the DCP066 reports), DUoS charging models and Ofgem consultations for the price review process, are made available to all network users, it is network users who are tasked with using this information to manage the cash-flow risk from changes in network charges.

The only exception to this might be demand, where suppliers who operate within the market are likely to have early access to information on changes in demand from their own customers, given their need for this information to support wholesale contracting and retail strategy. However, as discussed in Section 2, suppliers will in large part only be able to see changes to their own demand, while the DNO is the only party that sees demand for the entire Grid Supply Point (GSP).

It would, therefore, seem to be a stretch to conclude that suppliers (or another stakeholder group) have significantly better information of future demand for *network access* than that available to the network companies. Smaller, more niche, suppliers in particular are likely to be disadvantaged with less than perfect information for tariff forecasting.

In conclusion, the allocation of cash-flow risk from unpredictable and volatile charges does not appear to align with the observations made above of who out of the available stakeholder groups has access to the best information for managing this risk. In the absence of reforms, (we discuss the options in Section 4, including Ofgem's proposals) this would suggest there is currently a misallocation of risk arising from DNO pricing volatility.

3.1.2. Risk elasticity

This refers to the capacity of different stakeholder groups to respond or change their behaviour and actions in response to network pricing volatility and, therefore, to effectively manage their cash-flow risk from charging volatility.

Currently movements in network charges are largely an unhedgeable risk for suppliers and end consumers due to lack of long term products and supporting contractual arrangements for managing these risks. This is not the case for other elements of the total energy bill, where the supplier or consumer can take actions to manage their risk. For example, suppliers buy much of their energy requirement over a period of time through forward contracts in order to reduce the effect of large changes in wholesale prices, a practice known as hedging.

Hedging commodity costs helps suppliers to provide more certainty of future costs. This allows firms to manage risk against large increases in the commodity cost of energy and charge their customers a less volatile price than if they did not hedge. As highlighted in Section 2, less volatile energy prices (through hedging) are a service provided by suppliers which is valued by end consumers as directly revealed through their willingness to enter and pay for predictability through capped or fixed price energy deals.

This is not an option available for network costs:

- While long term products have been discussed through the implementation of the CDCM and EDCM, "hedging" products have yet to be implemented.[11] This prevents suppliers, and end consumers who engage directly with their network charges, from hedging a key component of the final bill.
- While one way that sources of risk (for example, changes in network charges that affect certain customer groups differently from others) can be managed is through portfolio diversification, this is not an option available for all players, particularly smaller suppliers who are more exposed to particular segments of the market.

[11] We understand that this is due to regulatory structure issues.

In addition, the DNOs are the monopoly distribution service provider for their respective local service areas. This means that both domestic and non-domestic customers are not able to reduce their exposure to differences in networks charges. Their ability to respond, or indeed mitigate unpredictable charges, is also restricted.

It is for this reason that as part of the RMR consultation, and to help customers to understand and engage with the market to compare offerings, EDF Energy has called for common networks charges to strip away a further layer of complexity.[12] While we do not consider this option further in our report, it reflects a general principle of lack of customer capacity to manage their network costs.

The DNOs also lack a general capacity to manage charging volatility on behalf of their customers. While they are able to provide timely information to improve the predictability and visibility of their charges, the DNOs regulatory regime is a revenue cap which means the amount of money they can recover from their customers is fixed through the terms of the licence.

This means that were a DNO to seek to provide less volatile and more predictable charges through smoothing revenue recovery through its charges, smoothing other than that allowed by Ofgem at the price review determination, it risks not achieving cost recovery or not being remunerated for the (opportunity) costs of managing the cash-flows (for example, were revenues deferred).

Indeed, under current licence arrangements, DNOs face restrictions of the amount of revenue that can be recovered ahead or carried forward in any year before regulatory restrictions apply to the charge setting in the following year. DNOs are also penalised for over recovery of allowed revenue (at Libor) under this mechanism.

The conclusions are clear:

- network charges are largely an unhedgeable risk for suppliers and other network users while being a significant component of the end consumer bill;
- while long term products for network charges have been discussed by the industry hedging products have yet to be implemented;
- suppliers and end consumers, while having some informational tools available, generally lack the capacity to manage their risk;
- a conclusion which is similar for the DNO given the restrictions placed on their revenue recovery under the licence.

As all stakeholder groups face some form of restriction on their capacity to respond or change their behaviour in response to network pricing volatility this would suggest that a change in the current arrangements should relax these restrictions to allow the stakeholder group who is best placed to manage the cash-flow risk. Clearly a key consideration in this is the cost of managing this risk, an issue we turn to in the subsection which follows.

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[12] Given that DNOs will have individual settlements under the price control, EDF Energy has asked Ofgem to consider establishing a clearing house to levelise DNO revenues resulting from setting a flat national charge.

3.1.3. Cost of risk

If there is a financial cost of managing network pricing volatility this raises the question of who has the lowest opportunity cost of managing this risk? In the subsections below, we consider how the cost of risk changes by stakeholder group, with a focus on comparing end consumer groups and their suppliers to the DNOs. Our focus is largely on the cost of accessing sources of cash and financing to meet unpredictable charges although our conclusions might also apply to more predictable changes in charges depending on the circumstances.

Is the domestic end consumer opportunity cost of capital higher or lower than the DNOs?

As highlighted in the introduction, in principle – assuming the end consumer's opportunity cost of managing more volatile energy bills is the social discount rate – an efficient allocation of risk is likely to be to pass the management of network pricing volatility to the consumer. Energy bills for domestic consumers are a proportion of disposable income with the end consumer able to manage the change in cash-flow through changes in their expenditure.

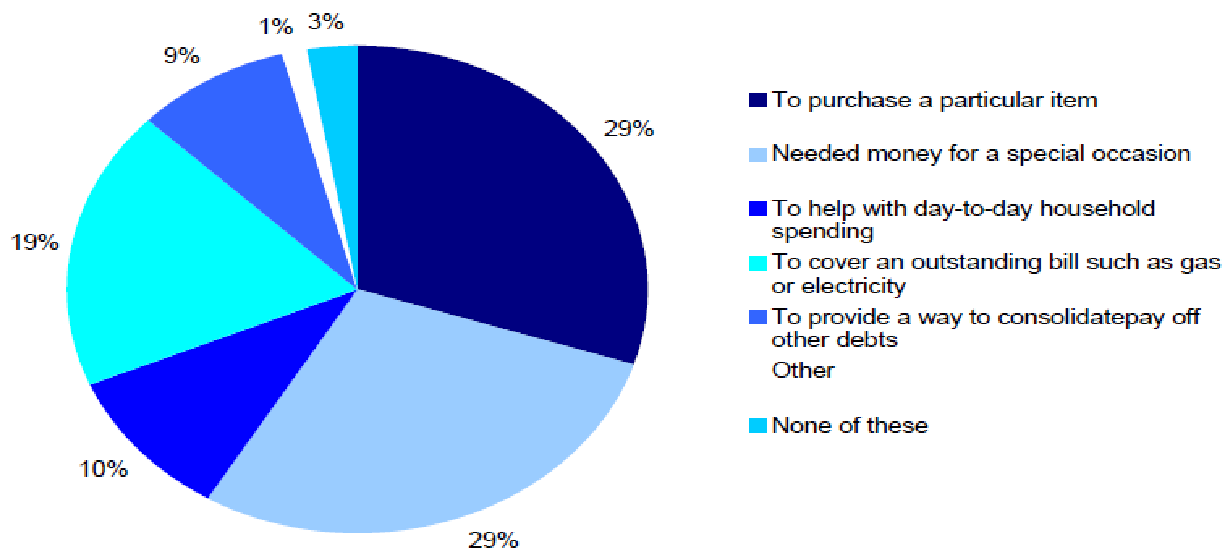
However, this assumes that all consumers have the disposable income available to fund increases in their bills. In practice some consumers are likely to face material costs in financing unexpected and volatile increases in their bills. This is more acute for low income households and fuel poor with an inelastic demand for energy.

Recent OFT research (2010)[13] has found that while a substantial amount of adult consumers in the UK do not make significant use of credit (their survey suggested more than half (56 per cent) of adult consumers made no use of credit beyond possessing credit cards and have current accounts with overdraft facilities) there are also segments of adult consumers who are experiencing a degree of financial distress, and difficulty in repaying their debts, and rely quite heavily on mainstream credit and store cards as well as payday loans.

The OFT reports that a substantial proportion of financially distressed consumers who held either a credit or store card, or relied on other home credit products such as payday loans, reported the reason they had taken out the card or the loan was to cover an outstanding bill such as gas or electricity. Figure 3.1 shows results from an OFT survey, where one of the main uses of consumer home credit was for the purchase of specific products or to meet the costs of specific occasions (a standard feature of credit use to smooth consumption). However, substantial minorities also reported using home credit to pay off outstanding bills such as gas or electricity.

[13] OFT (2010): 'Supplementary analysis from the OFT's consumer survey and other sources of data'

Figure 3.1: Home credit – main purpose of loan



Source: OFT Survey

Domestic consumers who fund changes in their energy bills by means other than disposable income, clearly face a far more material cost of funding network charges than the social discount rate which reflects time preference of consumption.

Is the non-domestic end consumer opportunity cost of capital higher or lower than the DNOs?

This principle in the domestic sector, we believe also extends to non-domestic consumers, particularly businesses, and large energy users, where energy costs (including network charges) form a high proportion of their cost base.

Business end-consumer cost of capital, as with the DNOs, is based on an assessment of business risk. While conclusions cannot be made definitively, the DNOs, who face a regulatory regime and cost of capital linked to the RAV and regulator financeability duties, are generally considered by financial markets to be low risk businesses relative to many other sectors of the economy. The DNOs are also large businesses, and compared to SMEs, have larger balance sheets and access to finance to manage the cash-flow risk at a low cost funds.

Therefore, compared to the DNOs, various non-domestic consumer groups, albeit depending on their circumstances, could face a significantly higher cost of risk managing these unexpected charges. This reflects that in many circumstance they have far less capacity to manage the cash-flow risk through their balance sheet as compared to the DNOs.

Is the supplier opportunity cost of capital higher or lower than the DNOs?

As supply businesses operate in a competitive market, their cost of capital of managing volatility and unpredictable charges may also be higher than the DNOs. Again, the link of DNOs cost of capital to the regulatory regime built around a RAB is likely to be a key influencing factor on the relative cost of funds of each stakeholder particularly in terms of accessing funds for unpredictable charges.

In contrast with the DNOs, suppliers operate in a market where customers are able to switch their supplier depending on market segment and the length of their contract. For example, in the domestic market, consumers can switch at any time, even in the case of fixed price contracts, as the consumer can pay an exit fee to leave the contract early, although this is not always required.

The ability to recover costs that are incurred but not passed-on to end consumers is therefore a key concern for the supply companies as typically contract supply margins are tight. As with similar risks in other contexts, this can be managed through charging (ex ante) an insurance premium whether the risk actually occurs or not.

But because suppliers face tight margins on their supply contracts, they might also be expected to charge an insurance premium (whether explicit or implicit) that errs on the side of caution to cover the increased cost risks (although this will depend on the risk appetite of individual suppliers). They also fear customers will change supplier and so may have to charge closer to a full cost premium rather than a probability adjusted one.[14] This may be particularly material for small suppliers who have less capacity to risk a shortfall, and so need to fully price risk, and potentially leads to a loss of market share, in the long run damaging competition.

Whether the impacts of the cash-flow risk, and the cost of risk from managing network pricing volatility, is less acute for the DNOs compared to suppliers, will of course also depend on the financial circumstances of the DNO:

- While a regulated price regime can facilitate revenue profiling as well as full and efficient network cost recovery, there is a limit before there may be implications for DNO financing costs and financeability.
- Large suppliers also have a balance sheet (and portfolio of customers) for managing and diversification of cash-flow risk, although this may not be the case for all suppliers particularly smaller ones who compete in particular segments of the market.

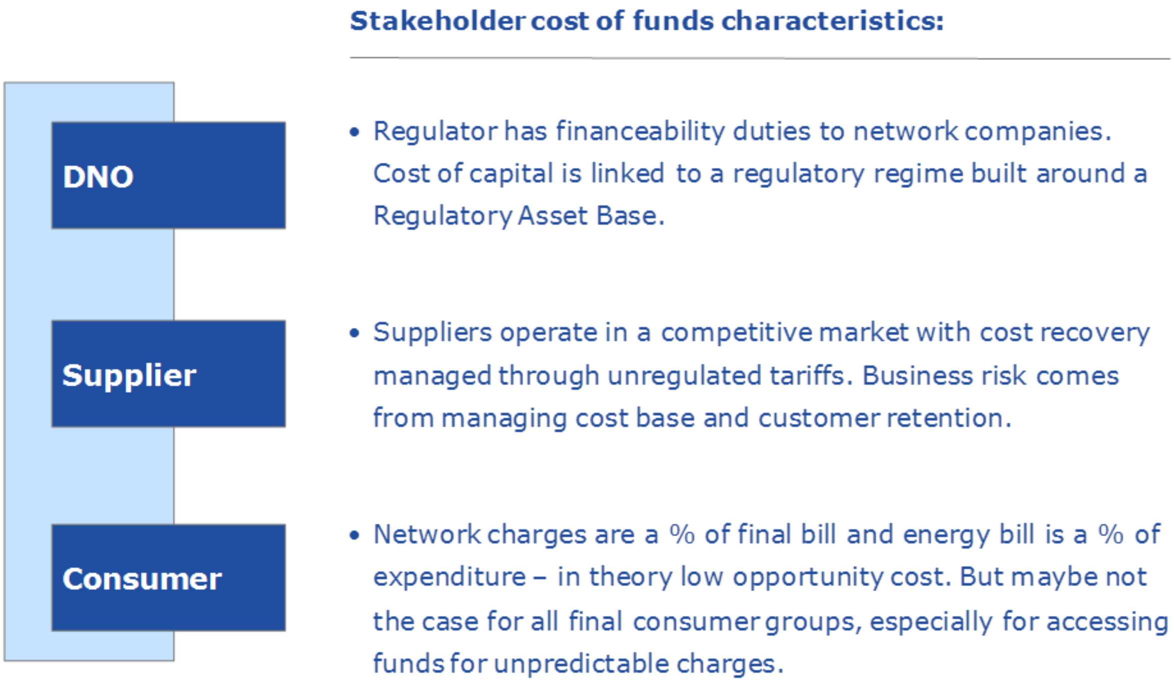
In general though, our view would be that the DNOs' business risk is substantially less than energy suppliers, and, therefore, the DNOs face a lower cost of financing whether for predictable or unpredictable charges, compared to suppliers.

[14] To avoid volatility of charges which might cause the customer to switch, the supplier might err on the side of caution when setting the premium that it includes in the customer's original quote.

Summary

Figure 3.2 summarises key characteristics of the cost of capital or funds for managing unpredictable and volatile charges by stakeholder group.

Figure 3.2: Stakeholder cost of funds characteristics



Source: CEPA

3.2. Stability or predictability?

Another issue is the dichotomy between price stability and price predictability. Feedback from a number of stakeholder groups has indicated some would like to see both. Our discussions with EDF Energy have highlighted that the issue may not just be about greater predictability and future visibility of charges. Although this would help, there may also be wider benefits from the DNOs using their balance sheets to smooth movements in their charges. In particular, this would provide suppliers with more predictable charges (as achieved through hedging for commodity costs) that are consistent with the fixed term contracts that many customers want.

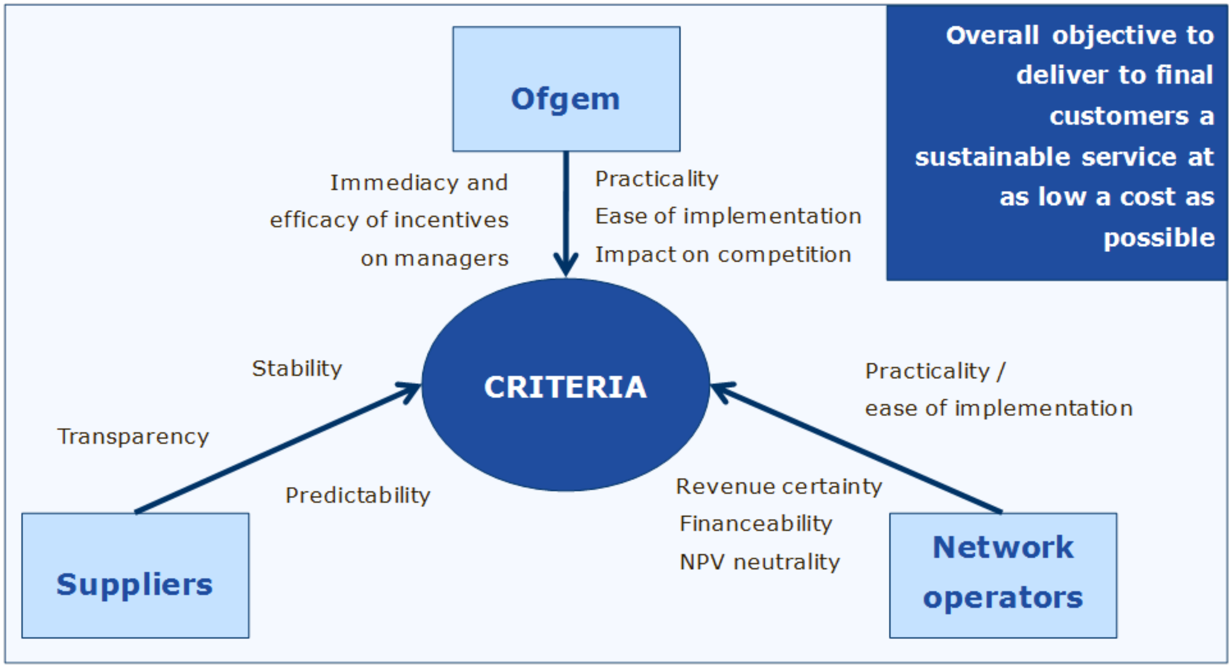
There may also be benefits for the DNOs from having greater stability of charges on their balance sheets in terms of seeking finance, as long as this can be managed efficiently without adverse effects on financeability. There are also, potentially benefits for market entrants in supply, who may currently be less able to manage the risks of volatile charging in setting pricing structures. We explore these issues further in Section 5. What they highlight is the transparency and stability of charges, as well as predictability, potentially has wider implications for enhancing competition in GB retail energy markets, and making the market work more effectively.

3.3. Objectives and criteria

Given the above, a number of stakeholder criteria and objectives need to be considered when evaluating the options for managing the network pricing volatility and unpredictability.

Our proposed criteria, as illustrated by Figure 3.3 have been used to inform our assessment of the options in Section 4 and 5.

Figure 3.3: Stakeholder criteria



Source: CEPA

3.4. Conclusions

This section has considered the economic principles which drive and ultimately underpin the issue of how to manage volatility of cost reflective network charges. It has also set out the core objectives and criteria that any reform options should seek to achieve and the issue of whether pricing stability or pricing predictability needs to be achieved.

The section which follows briefly reviews Ofgem's proposals for improving pricing predictability followed by some alternative approaches that would seek to more fundamentally alter the allocation of cash-flow risk from suppliers and customers to the DNOs. We then analyse the impacts of this reallocation of risk through cost benefit analysis.

4. PROPOSALS

This section reviews Ofgem's proposals for mitigating charging volatility and considers the alternative approaches which would result in a more fundamental reallocation of risk and cost of risk amongst stakeholder groups.

4.1. Ofgem's proposals

Ofgem has identified five options which could help to address network charging volatility, or its effects, arising from the price control process. These include improved information provision in relation to the expected changes to DNOs' allowed revenues, imposing restrictions on intra-year charge changes, more systematic approaches to the lagging of rewards and penalties associated with price control incentive mechanisms, automatic lagging of adjustments to allowed revenues from uncertainty mechanisms and a cap and collar on changes to allowed revenues. Ofgem has also set out an initial assessment of the options and its preferred solutions.

Ofgem has indicated that, in its view, the option of providing enhanced information provision, coupled with measures to help improve the predictability of areas such as incentives and the frequency of changes in charges, would be beneficial to the industry. However, Ofgem has indicated that the implementation of more structural measures (such as a cap and collar mechanism) would be unlikely to be of benefit, given the benefits to suppliers (and their customers) in terms of reduced risk would be unlikely to outweigh the potential increase in cash-flow risk for DNOs. Ofgem also highlighted the additional complexity that options such as the cap and collar would introduce to the regulatory regime.

We would highlight the following points from Ofgem's initial assessment:

- the options are predominantly focused on addressing the predictability (or lack of predictability) of charge changes;
- their design also focuses on addressing charging volatility within as opposed to between the price control (and does not address the mid-term review);
- the options considered to be beneficial by Ofgem are mainly informational in nature or providing greater visibility of allowed revenue changes;[15] and
- the allocation of cash-flow risk from network pricing volatility remains largely with suppliers and end-consumers as under the current arrangements.

Within the context of RIIO-ED1, this means that without alternative or additional proposals:

- suppliers and consumers, given the stage of the price review process, remain exposed to a price shock between price control settlements with little capacity to hedge this risk;

[15] The exception to this is the restriction on intra-year charge changes which would act to provide more certainty and stability of network charges.

- equally this applies to the mid-period control review of outputs (and therefore allowed expenditure) for which the scope and process remain uncertain;
- there is no single proposal on the table which would directly address the issue of *both* between and within price control charging volatility (e.g. from a P_0 adjustment); and
- perhaps most fundamentally, while Ofgem's proposals are likely to benefit both suppliers and end-consumers, they do not address the potential misallocation of cash-flow risk identified through Section 3.

4.2. Options

What then are the alternative options? EDF Energy has highlighted to us that while predictability and the visibility of DUoS charges is important (which Ofgem's proposals begin to address) they also consider there to be benefits from smoothing movements in DUoS charges, to provide a more efficient allocation of risk, and to provide suppliers and end-consumers with predictable charges that are consistent with the fixed term contracts that many customers want.

Options (and possible subsets of options) that might achieve or partially achieve this objective but are also consistent with the stakeholder criteria presented in Section 3 include:

- commitment by Ofgem to an early announcement of the P_0 adjustment at the start of RIIO-ED1 (with arrangements for adjusting revenues if this differs from the actual allowances);
- a similar commitment to the same arrangement (following the final determination for the eight year price review) for the mid-period control review (should this be needed);
- application of transparent and stable allowed revenue smoothing mechanisms for the DNOs in RIIO-ED1; and
- building on the proposals developed by Ofgem, a time limited notice period after which DNOs would not be able to amend their charges.[16]

However, none of these options would meet the objectives and criteria entirely. A more comprehensive approach would instead be to fix the DNOs DUoS charges much earlier than at present (by providing the notice period of future changes in tariffs) combined with a general DNO smoothing mechanism for RIIO-ED1 that would allow for DNO:

- revenue profiling;
- certainty of recovering revenue;
- net present value (NPV) neutrality; and
- overall financeability.

[16] This would potentially require the DNOs to re-profile their allowed revenue if there was an over or under recovery of revenue based on the charging statement fixed at the notice period date and the demand for distribution system access.

The governance and design of this mechanism would need to apply between and within the price control period to provide greater certainty of DUoS charges from the start of RIIO-ED1. It would allow for enduring revenue smoothing so as to provide:

- a vehicle for Ofgem and the DNOs to give greater transparency and predictability of tariff changes from the P_0 adjustment and the mid period review; but also
- additional predictability and stability of the volatility challenges under RIIO from incentives and changes in pass through costs.

The key issues that need to be considered in the design of this mechanism are outlined in the subsection below.

4.3. Mechanism design

The parameters of the mechanism include:

- What would the notice period apply to?
- How would revenue smoothing be managed through the DNOs revenue cap?
- How frequently would publication of tariff changes be allowed under the mechanism? And
- What would be the length of the notice period?

We consider each issue in the subsections below. An analysis of the costs and benefits and the incentives under different assumptions for each of these areas, is explored through our impact assessment in Section 5.

What would the notice period apply to?

To achieve the stability and predictability objectives intended, the notice period would need to apply to the statement of DUoS charges rather than just price control allowed revenue. This would mean the timeline of the notice period would also apply to the DNOs DUoS charging model inputs, including marginal cost estimates and demand data.

How would the revenue smoothing be managed through the DNOs revenue cap?

The notice period would mean that fixed network tariffs are published one, two or more years ahead plus the current three months notice. Any difference between the DNOs' recovered revenue (through the fixed notice period tariffs) and actual allowed revenue would:

- be recovered at the next available tariff notice period date (this would mean that the increase in tariffs would be known with certainty by suppliers and consumers); with
- the DNO compensated for the opportunity cost of any changes in the profile of revenue recovery (positive or negative) so that the smoothing mechanism was NPV neutral; and

- the cost of capital set at the price control allowed WACC plus an uplift for inflation (dependent on the period over which revenues are smoothed).

An important objective for the revenue smoothing mechanism (particularly at the start of the price control period) would be:

- to establish a profile of revenue recovery that would avoid sharp and unexpected changes in distribution charges while at the same time; is
- reflective of the timing and scale of work that needs to be delivered by the DNOs so to provide for financeability.

How frequently would publication of tariff changes be allowed under the mechanism?

The mechanism would also need to provide certainty that there would be no within year changes in charges a proposal already being considered by Ofgem through its consultation paper.

What would be the length of the notice period

Options for the length of the notice period before the charges come into effect include:

- 15 months;
- 27 months; or
- 39 months.

The choice of length of notice period is linked to the duration of contracts which would be "de-risked" from unexpected changes in DUoS charges. Figure 4.1 illustrates the issue, showing how different contract durations map to the RIIO-ED1 and DUoS tariff timetable.

In this example, we have assumed the supplier only offers fixed price deals at the start of the quarter, although clearly a new customer could come along at any point in time and request a fix price supply deal of varying lengths.

Figure 4.1 shows that as the duration of contract fix increases, suppliers need earlier information on future DUoS tariff changes, where for example a three year fixed price contract would not be entirely captured under a 15 month notice period design.

The choice of notice period, and the retail contracts which would be captured through the mechanism design, is also linked to how frequently publication of DUoS tariff changes would then be allowed under the mechanism.

For example, under a 15 month notice period, charges published in December 2012 for 2013 through to March 2014, would provide certainty for both one and the majority of two year contracts, providing there was certainty that there would be no within year changes.

Figure 4.1: Illustrative contract durations

Year	2012				2013				2014				2015				2016				2017				
Financial year		2012/13				2013/14				2014/15				2015/16				2016/17				2018/18			
Price control year		DPCR5 year 3				DPCR5 year 4				DPCR5 year 5				RIIO-ED1 year 1				RIIO-ED1 year 2				RIIO-ED1 year 3			
Quarter	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
1) RIIO-ED1																									
Milestones			Strategy doc published						Fast track decision	Initial proposals		Ofgem final proposals		Year 1 DUoS				Year 2 DUoS				Year 3 DUoS			
2) When do suppliers need to know about RIIO-ED1 tariff changes - 1-year contract fixes?																									
Contract start - Q3 2014											1	2	3	4											
Contract start - Q4 2014												1	2	3	4										
Contract start - Q1 2015													1	2	3	4									
Contract start - Q2 2015														1	2	3	4								
Contract start - Q3 2015															1	2	3	4							
Contract start - Q4 2015																1	2	3	4						
Contract start - Q1 2016																	1	2	3	4					
2) When do suppliers need to know about RIIO-ED1 tariff changes - 2-year contract fixes?																									
Contract start - Q3 2013							1	2	3	4	5	6	7	8											
Contract start - Q4 2013								1	2	3	4	5	6	7	8										
Contract start - Q1 2014									1	2	3	4	5	6	7	8									
Contract start - Q2 2014										1	2	3	4	5	6	7	8								
Contract start - Q3 2014											1	2	3	4	5	6	7	8							
Contract start - Q4 2014												1	2	3	4	5	6	7	8						
Contract start - Q1 2015													1	2	3	4	5	6	7	8					
Contract start - Q2 2015														1	2	3	4	5	6	7	8				
Contract start - Q3 2015															1	2	3	4	5	6	7	8			
3) When do suppliers need to know about RIIO-ED1 tariff changes - 3-year contract fixes?																									
Contract start - Q3 2012			1	2	3	4	5	6	7	8	9	10	11	12											
Contract start - Q4 2012				1	2	3	4	5	6	7	8	9	10	11	12										
Contract start - Q1 2013					1	2	3	4	5	6	7	8	9	10	11	12									
Contract start - Q2 2013						1	2	3	4	5	6	7	8	9	10	11	12								
Contract start - Q3 2013							1	2	3	4	5	6	7	8	9	10	11	12							
Contract start - Q4 2013								1	2	3	4	5	6	7	8	9	10	11	12						
Contract start - Q1 2014									1	2	3	4	5	6	7	8	9	10	11	12					
Contract start - Q2 2014										1	2	3	4	5	6	7	8	9	10	11	12				
Contract start - Q3 2014											1	2	3	4	5	6	7	8	9	10	11	12			
Contract start - Q4 2014												1	2	3	4	5	6	7	8	9	10	11	12		
Contract start - Q1 2015													1	2	3	4	5	6	7	8	9	10	11	12	
Contract start - Q2 2015														1	2	3	4	5	6	7	8	9	10	11	12

4.4. Overall outcomes

The overall and fundamental outcome of these proposals is to reallocate management of the cash-flow risk arising from the inherent volatility and unpredictability of DUoS charges away from suppliers and end-consumers to the DNOs. This is based on the analysis in Section 3 that in many circumstances the DNO may be best placed to manage this risk from both an informational and cost of risk perspective. We seek to test this hypothesis further through qualitative and quantitative analysis in the section which follows.

5. ASSESSMENT

This section provides our quantitative and qualitative assessment of the impacts of a notice period and smoothing mechanism by affected stakeholder groups. First we present the results of our quantitative assessment of the notice period mechanism. This is based on a modelling framework developed by CEPA which analyses the impact of future DUoS pricing volatility and unpredictability by stakeholder groups.

5.1. Quantitative assessment

5.1.1. Approach

As the cost of risk from network charging volatility is reflected in the consumer bill in the form of a risk premium, our model sought to assess an "implied" risk premium through modelling supplier forecasting errors of an "average" DNO's DUoS charges arising from:

- the reset of the price controls at RIIO-ED1; and
- volatility within the price control.

These forecasting errors were applied to a supplier portfolio of network demand by DUoS customer group to calculate a forecast implied risk premium. For each customer group in the portfolio, a fixed proportion of customers were assumed to be on fully variable retail tariffs and one-year, two-year and three-year fixed price retail tariffs. For:

- customers on variable tariffs, it was assumed any changes in network costs could be passed straight through by suppliers into the retail tariff;[17] but
- for fixed price retail tariffs, forecasts of future DUoS charges paid by the supplier would be used to set the network component of the fixed price deal.

The model used expectation rules for how suppliers would then predict DUoS charges when having to fix the network cost component of the fixed price retail tariff. These rules defined the supplier forecasting errors produced in the modelling.

The risk premium was "implied" in that it reflected the cost of risk a supplier would need to add to final consumer annual DUoS charges to maintain a targeted supply margin given a scenario of charging volatility. As a reflection of modelled supplier forecasting errors, it was assumed this implied premium was then added to the final consumer bill resulting in a modelled cost of risk from DUoS charging volatility for the end-consumer. Hence the implied premium.

Having modelled an end-consumer cost of risk without a notice period regime for charges, the model was then also able to assess how a notice period could reduce the implied risk premium, and

[17] This is a conservative assumption. In practice there can be a time lag before changes in network costs can be reflected in retail prices hence why within year network charging volatility creates risks even for end-consumers on variable price contracts.

therefore consumer cost of risk, by providing suppliers with more predictability and certainty of their future DUoS charges. We also modelled the costs the DNO could incur from providing a notice period of its charges.

Our modelling approach is described in more detail in Annex A along with the assumptions we adopted in our model.

5.1.2. Scenarios

A number of scenarios were tested through the model to reflect future profiles of DNO's base allowed revenues, allowed revenue adjustments (e.g. incentive payments) and how this was reflected in the contract and pricing decisions made by suppliers for end-consumer bills. The four core scenarios adopted in the model are described in Table 5.1.

Table 5.1: Modelling scenarios

<table>
<tr><td></td><td colspan="3">DNO Revenue profiling</td></tr>
<tr><td rowspan="3">Supplier DUoS tariff forecasting</td><td></td><td>P_0 with zero ongoing X</td><td>Constant percentage X</td></tr>
<tr><td>Adaptive expectations</td><td><u>Scenario 1</u>
• Step change in DNO allowed revenue at the start of RIIO-ED1.
• Supplier uses an adaptive expectation rule to predict DUoS tariffs.
• This involves pricing off a projection of base allowed revenue.
• Plus a backward looking adaptive rule for adjustments (e.g. incentives) above base revenue.</td><td><u>Scenario 2</u>
• Constant "X" increase in DNO allowed revenue through profiling.
• Supplier uses an adaptive expectation rule to predict DUoS tariffs.
• This involves pricing off a projection of base allowed revenue.
• Plus a backward looking adaptive rule for adjustments (e.g. incentives) above base revenue.</td></tr>
<tr><td>DNO forecasts</td><td><u>Scenario 3</u>
• Step change in DNO allowed revenue at the start of RIIO-ED1.
• Supplier predictions of DUoS tariffs are based on a DNO forecast.
• These are assumed to be consistently less than actual DUoS tariffs.
• This reflects a consistent negative error term for the supplier.</td><td><u>Scenario 4</u>
• Constant "X" increase in DNO allowed revenue through profiling.
• Supplier predictions of DUoS tariffs are based on a DNO forecast.
• These are assumed to be consistently less than actual DUoS tariffs.
• This reflects a consistent negative error term for the supplier.</td></tr>
</table>

Source: CEPA

For Scenarios 3 and 4 we modelled a state of the world where the supplier and the DNO (when required to provide a notice period of its DUoS charges) systematically *under* forecast the revenue that needed to be recovered from network users. This was to reflect the underlying objective of our model which was to test the benefits of a notice period regime for the end-consumer, and the impacts on DNO financeability, if the risk for the supplier of charging a future price below their actual network costs (the implied risk premium) were reduced. We discuss alternative states of the world and the possible outcomes in Section 5.1.7.

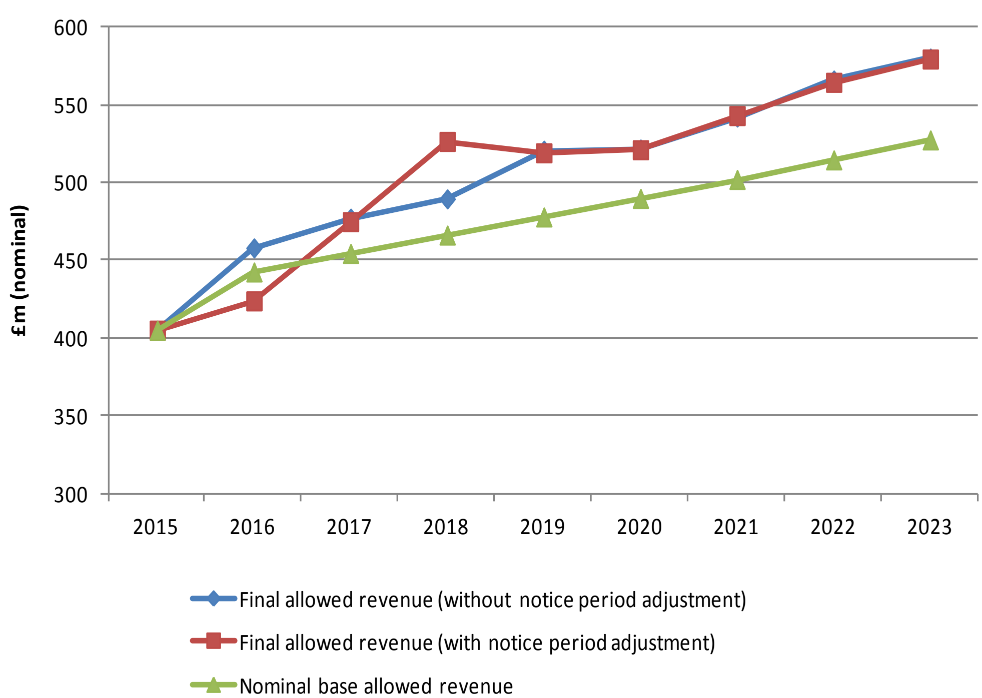
The model tested the impact of the notice period mechanism (under alternative assumptions – e.g. 15 month, 27 month and 39 month durations) under four scenarios of supplier DUoS tariff forecasting and revenue profiling.

As four scenarios were tested through our model, the results of our analysis, particularly as regards the results of the cost benefit analysis, are presented as ranges to reflect the uncertainty around the key variables and assumptions in our model.

5.1.3. DNO impacts

We built a price control financial model for an average DNO using the same approach as Ofgem adopted for the DPCR5 determination. This was extended to include RIIO-ED1 so as to project allowed revenue into the forthcoming price control period (to 2022/23) based on future DNO cost assumptions. As illustrated in Figure 5.1 below, using the financial model we were able to model the impact of different durations of notice period and revenue smoothing mechanism, on the DNO's allowed revenues, cash-flow and DUoS charges given projected costs. In this example, we show the impact of a 15 month notice period duration.

Figure 5.1: Scenario allowed revenue profiles – 15 month notice period



Source: CEPA

In this scenario, there is step change in allowed revenue (a P_0 adjustment) at the start of RIIO-ED1. As the DNO under forecasts the change in revenue from the transition to RIIO-ED1 (when providing the 15 month notice period for tariffs) part of the allowed revenue from year 1 is deferred and recovered in year 3 of RIIO-ED1.

This is illustrated by the red line being below the blue line for year 1 of RIIO-ED1 but above the blue line in year 3 (when the deferred revenue is recovered with an added opportunity cost of capital). In the later years of RIIO-ED1, the blue and red lines are similar because the DNO only needs to forecast revenue adjustments rather than the reset of the price control review.

By constructing financial statements for the average DNO, we were also able to complete a high-level financeability assessment of the impact of the notice period regime and the revenue smoothing approach on an average DNO. Figure 5.2 (overleaf) shows the results from the financeability tests for each notice period duration for Scenarios 2 and 4 (results for all four scenarios are provided in Annex A). It shows, given the model assumptions and therefore cash-flows involved, that the notice period regime has only a very minor impact on DNO financeability threshold tests.

Of course, this result is for an average DNO and financeability outcomes and tests would be expected to differ for an actual DNO. As highlighted in Annex A, we have assumed a relatively gentle ramp up in costs at the start of RIIO-ED1. Were there a much more dramatic ramp up in DNO capex right from the start of RIIO-ED1 then this would be expected to place more pressure on the DNO's financeability thresholds. We note however, that historically capex has tended to ramp up after the first few years of the price control[18] and Ofgem would be considering financeability tests in profiling of allowed revenues, as it has indicated for RIIO-T1 and RIIO-GD1.

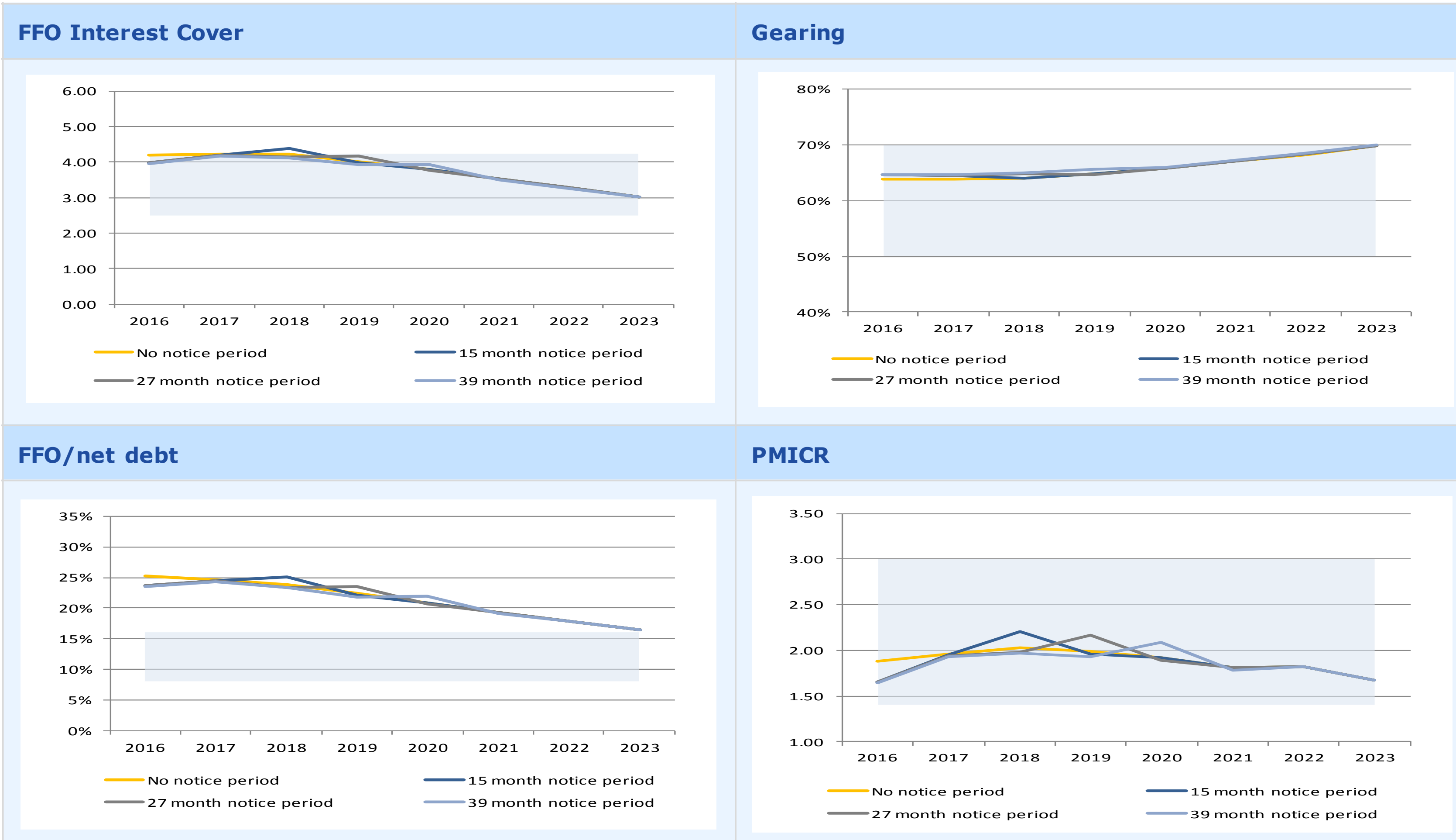
Under the notice period and revenue smoothing mechanism, as described in Section 4, DNOs may be required to defer recovery of their allowed revenues in order to provide the certainty of DUoS tariffs at the notice period date. This would incur a financing cost from the re-profiling of allowed revenue, ultimately reflected in the end-consumer bill.

However, as discussed in Section 3, there could also be benefits for the DNO from having greater stability of charges on their balance sheets under the revenue smoothing mechanism, in terms of seeking finance, as long as this can be managed efficiently without adverse effects on financeability. Our model did not seek to quantify any such benefits.

Similarly because the model's average DNO passes its financeability tests, and revenue smoothing and profiling is NPV neutral, we also assumed there is no impact of the proposed mechanism on DNO financing costs (i.e. cost of capital). DNO net welfare under each notice period duration is, therefore, also assumed to be zero as DNO allowed revenues are recovered in full through a NPV neutrality re-profiling mechanism.

[18] This reflects that the DNOs would have, or would currently need to be in the process of, procuring contracts for capex projects were a rapid ramp-up in investment required in the first year of the price control.

Figure 5.2: Financeability / credit metrics



Source: CEPA

Note: shaded area denotes target range for financeability ratio; if the financeability ratio goes below the shaded area then the financeability ratio test is failed. The exception to this is gearing where the financeability test is gearing below 70%. Larger charts for each financeability ratio are provided in Annex A.

5.1.4. Supplier impacts

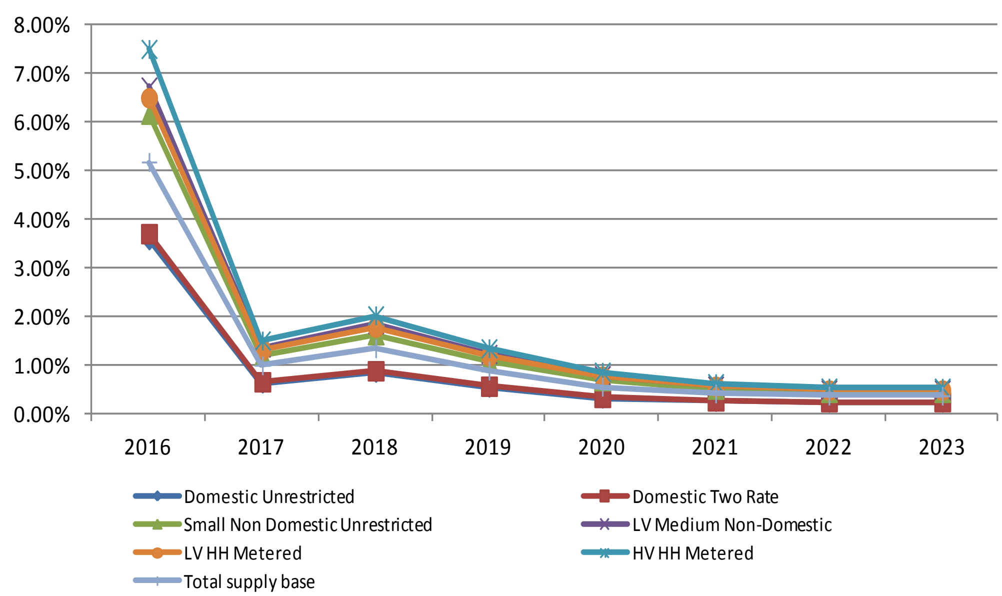
As described above, the supplier modelling assessed the impact of DUoS charging volatility on suppliers (in terms of network cost recovery from final electricity consumers) by building a portfolio of demand customers by DUoS customer group. The DNO model converted each year of allowed revenue into a set of DUoS charges for these customer tariff groups.

These DUoS charges, under different assumptions of supplier DUoS tariff expectation rules, were then used to assess a set of supplier forecast or predicted DUoS charges, which were then compared to the actual DUoS charges paid by the supplier to the DNO (based on the actual DNO revenue allowed under the price control).

Any difference between these amounts was used to calculate the implied risk premium under the model scenario. In the model, this is the premium that the supplier would need to pass-through to the end-consumer bill to mitigate or hedge against the volatility and unpredictabiltiy of DUoS charges, caused by the forecast reset of the price control and within period volatility.

Modelled supplier risk premia by DUoS customer group for one of our model scenarios, and without the notice period mechanism, are illustrated in Figure 5.3 below. This reflects a blended risk premia for customer groups and so includes customers on varying lengths of variable, one-year, two-year and three-year fixed price energy deals. The high implied risk premia in the first year of the price control reflects the modelled P_0 adjustment in allowed revenues.

Figure 5.3: Modelled implied supplier risk premia without a notice period regime



Source: CEPA

As for the DNO, change in supplier welfare from the notice period regime, is assumed to be zero in the model, as any reduction in the implied risk premia arising from the notice period regime (caused by greater predictability and certainty of DUoS charges under the notice period) is passed-through to the end-consumer as a reduction in final energy prices. This reflects an underlying assumption that electricity suppliers are competitive, and that a reduction in the supplier cost of risk is competed away so suppliers earn a normal profit.

5.1.5. End consumer impacts

The impact on end-consumers was the combined impact, i.e. changes in costs and benefits, modelled for the DNO and supplier passed-through to the final energy price. Our model did not seek to assess the costs and benefits of changes in cash-flows on the end-consumer independently although as discussed in Section 3 it might be argued that more certain and predictable charges could also be of direct benefit for the end consumer. This may mean our quantitative analysis understates the net benefits of the notice period regime.

5.1.6. Cost benefit analysis

Table 5.2 shows the results from the cost benefit analysis. It suggests that based on the modelling and its assumptions the notice period regime would result in a net benefit in end-consumer welfare from a reduction in the costs of suppliers managing DUoS pricing volatility and a relatively smaller increase in DNO costs from managing this cash-flow risk. The cost benefit analysis results for each of the four scenarios are provided in Annex A.

Table 5.2: CBA (NPV - £m nominal) – change in welfare relative to scenario with no notice period

		Duration of notice period					
		15 month		**27 month**		**39 month**	
		Min	**Max**	**Min**	**Max**	**Min**	**Max**
DNO welfare	DNO borrowing costs	-3.8	-8.2	-6.8	-13.6	-11.8	-21.3
	DNO recovered carry costs	+3.8	+8.2	+6.8	+13.6	+11.8	+21.3
	Change in DNO welfare	-	-	-	-	-	-
Supplier welfare	Supplier implied risk premia	-21.9	-45.4	-23.2	-49.1	-24.3	-63.0
	Supplier recovered risk premia	+21.9	+45.4	+23.2	+49.1	+24.3	+63.0
	Change in supplier welfare	-	-	-	-	-	-
Consumer welfare	DNO costs	+3.8	+8.2	+6.8	+13.6	+11.8	+21.3
	Supplier costs	-21.9	-45.4	-23.2	-49.1	-24.3	-63.0
	Change in consumer welfare	+18.1	+37.2	+16.4	+35.5	+12.5	+41.8
Reduction in DUoS charging cost of risk		+18.1	+37.2	+16.4	+35.5	+12.5	+41.8

Source: CEPA

To put the results into perspective, we estimate that average nominal DNO base allowed revenue (for the sector as a whole) in DPCR5 to be around £4.5-5bn per annum. Based on our model results, the notice period and smoothing mechanism if applied to all DNOs could be able to deliver a saving for the end consumer of somewhere around 0.5-1.5% of DNO allowed revenue or around £40 million per annum. This is not a reduction in DNO actual allowed revenue, but a reduction in the cost of risk from charging volatility.

5.1.7. Additional considerations

In this section we highlight some additional points that need to be considered when interpreting the results from the modelled cost benefit analysis. This includes:

- impacts of the mid-period review; and
- alternative states of the world.

Mid-period review

As highlighted in Section 2, an important change under RIIO is that eight year price controls will include a limited window ("re-opener") after four years to review the price controls focused on the outputs delivered by the DNOs.

This mid-period output review introduces an additional source of uncertainty to the DUoS charge setting process, potentially creating two pricing 'cliff-edges' rather than one, and hence higher cash-flow risk borne by suppliers and end- consumers.

We have not sought to model the impact of the mid-period review given the uncertainty of its content.[19] However, the mid-period review in any scenario adds an additional source of risk which may again mean that our quantitative analysis understates the net benefits of implementation of a notice period and smoothing regime in RIIO-ED1.

Alternative states of the world

As discussed above, our model focused on a state of the world where the supplier and DNO (when required to provide a notice period of its DUoS charges) systematically *under* forecast the revenue needed to be recovered from end-consumers and network users respectively. This was to reflect the underlying objective of our model which was to test the benefits of a notice period regime, if the risk for the supplier of charging a future price below their actual network costs (the implied risk premium) were reduced.

However, an alternative assumption that could also have been explored through the modelling would have been a scenario where the DNO (either through the revenue forecasts provided under the DUCSA or under the notice period regime) over rather than under forecast the revenue it needed to recover from network users. As discussed in Section 2, in the absence of a notice period,

[19] Indeed if a mid-period review of RIIO-ED1 will be required at all.

were the supplier to adopt these forecasts, this would result in an over recovery of network costs from the end-consumer. This would mean:

- that the end-consumer is again left worse off from the volatility and unpredictability of DUoS tariffs; in addition
- given DNO forecasts are by definition forecasts,[20] there remains a supplier risk of charging a future price below their actual network costs when the retail price is struck; hence
- when setting retail contract tariffs, the supplier would need to continue to charge an insurance premium that is recovered whether the risks concerned occur or not.

In contrast, in a state of the world where the DNO over rather than under forecasts its allowed revenue for setting a notice period statement of charges, the notice period and revenue smoothing mechanism would have the following outcome:

- it would ensure over recovered network charges from the DNO forecasting error results in a future reduction in network charges (as required by the price control regime);
- an opportunity cost (at the price control WACC) would also be added to the revenues returned through lower network charges;
- as a result, the supplier passes these reductions in network charges to consumers through lower future retail tariffs; and
- any additional risk premium that the supplier may add from the expected distribution of risk around the DNO forecast of allowed revenue is also reduced.

The conclusion is that while the cost-benefit analysis in Table 5.2 reflects a state of the world where the DNO under-forecasts its allowed revenue, a notice period regime with revenue smoothing mechanism would also result in an improvement in consumer welfare if over-forecasts occur.

This reflects the situation under current arrangements; there is a cost of risk for the end-consumer whether the pricing forecasting error is positive or negative. This may materialise explicitly or through the margin that suppliers are willing to accept for a customer contract.

5.2. Qualitative assessment

Our quantitative analysis has been based on a detailed modelling framework that is necessarily dependent on a series of assumptions, including supplier pricing expectation rules. As such, whilst the modelling is valuable in enabling a number of hypotheses to be tested, its results must be placed in the context of a wider qualitative assessment and economic rationale, in which it is used to support conclusions rather than its outputs being seen as definitive.

[20] The supplier does not know this is an over-forecast at the time the information is made available to the market.

The sub-sections which follow consider the impact of the proposed notice period and smoothing mechanism (including alternative assumptions of notice duration) on:

- DNO management incentives;
- DNO revenue forecasting incentives;
- energy market competition;
- financeability; and
- overall economic rationale.

5.2.1. Management incentives

The delay of price control incentive payments through the profiling of allowed revenues under the notice period and smoothing mechanism might be argued to reduce the immediacy of incentive payments on profits and, therefore, the efficacy of incentives on DNO managers (an objective under RIIO for efficiency incentives). However, price control incentive arrangements aim to impact on DNO management actions and performance as well as profits.

While management remuneration will be linked to incentive performance and profits this is possibly separable from the actual allowed revenue that flows through to charges in any particular year.[21] Consistent with Ofgem's proposals to lag efficiency incentive payments under the RIIO regime, we do not believe there would be a substantive negative impact on management incentives from the revenue smoothing that could need to take place under a notice period regime.

5.2.2. Forecasting incentives

As discussed through the modelling, introducing a notice period essentially means shifting the burden of forecasting from the supplier to the DNO, which is preferable because of the low opportunity cost of capital for the DNO. Under this new regime, it might be argued that the DNOs have an incentive to over forecast their revenue to front load their cash-flow and prevent any financeability issues from occurring.

While this scenario would still reduce charging uncertainty for suppliers and consumers, with the improvement in net consumer welfare highlighted through our quantitative analysis, it would be an unintended consequence of the policy if allowed revenue was continually over forecast by the DNO. We believe however, that this effect is reduced because the DNO would still face the overall revenue cap for that charging year. Therefore:

[21] For example, ENW executive directors short term corporate objectives are based on a balanced scorecard approach with approximately 55% of the total related to financial performance and efficiency and 45% of the total comprising key operational metrics. A long term bonus (from 1 April 2010 to 31 March 2015) is also in place, based on financial performance and comparative performance, as assessed by Ofgem, and is deferred until June 2015. See Statement of directors remuneration (section 42C) available: here.

- if the DNO were to over-forecast in one year, this would only result in reduced allowed revenue in a future year (when would depend on the notice period duration); furthermore
- there is no benefit from a returns perspective as any advanced cash-flow would be returned to consumers with an opportunity cost of capital.

This assumes that the DNO cost of capital is equal to the allowed cost of capital. If the DNO WACC is below that allowed under the price control then in theory there would be a benefit for the DNO from under forecasting its allowed revenue.

However, given the above, and some of the benefits for the DNO from more stable charges (as discussed in section 3.2), we think it is more likely that the DNOs would seek to achieve as stable tariffs as possible from the notice period and smoothing mechanism by seeking to forecast future allowed revenue changes as accurately as possible.

5.2.3. Competition

Current RMR proposals seek to introduce greater transparency and simplicity of tariff information for the final customers to support competition in the retail supply market. An important part of the policy package is for fixed price contracts to act as a platform for suppliers to compete and innovate outside the standard evergreen tariff.

If indeed those contracts provide the opportunity for a supplier to genuinely innovate, then the profitability of those contracts also becomes important for supplier business models, market entry and competition. The attractiveness (or riskiness) of those contracts to different players becomes an element of effective retail competition in the GB market.

If network charging volatility is a risk associated with fixed price contracts (and a non-hedgeable risk, particularly for smaller players with less scope to manage the risk within a portfolio) it might be argued that unless network charging volatility affects all suppliers in the same way (through an industry smoothing mechanism such as a fixed 15 month notice period) then it potentially acts as a barrier to entry and effective competition in the market.

These points have been made in previous sections. However, for the purposes of reaching conclusions from our impact assessment, we would note that potential (albeit unquantifiable) benefits for retail competition from reducing supplier cash-flow risk through the charging notice period, would only act to strengthen the conclusion that the regime and smoothing mechanism will result in an improvement in net consumer welfare.

5.2.4. Financeability

A key impact of the charging notice period is the potential need for the re-profiling of allowed revenues to ensure full (efficient) cost recovery for the DNO. One implication of this is that the notice period and its potential impacts will need to be considered in Ofgem's financeability testing at the time of the price control review, for example, through scenario analysis.

5.2.5. Overall economic rationale

In this section we have provided additional qualitative analysis of the impacts of a notice period regime. Overall our conclusion is that:

- providing greater certainty for tariff decisions by publishing fixed network charges earlier (i.e. a minimum notice period) will result in an improvement in net-consumer welfare; as
- the benefits (in terms of competition impacts and reduced supplier risk premiums) will likely exceed any costs of providing the notice period.

Fundamentally our conclusion rests on the economic rationale that the DNOs have the capacity to manage the cash-flow risk from charging volatility (through their price control and balance sheet) more effectively and at a lower opportunity cost of funds than other stakeholder groups.

6. CONCLUSIONS

This report has considered the economic principles underlying options to manage network pricing volatility including the future profile, stability and predictability of the DNOs DUoS charges. We have been asked by EDF Energy to consider alternative approaches to the current arrangements building on the proposals already made by Ofgem through its work on mitigating network charging volatility.

Overall our conclusions are that:

- current arrangements for managing the cash-flow risk from DUoS charges may not lead to the most efficient allocation of risk, and therefore cost of risk;
- the options we have evaluated could provide greater certainty of future DUoS charges and a more efficient allocation of risk; and
- there are potential benefits for a range of industry stakeholder groups, including suppliers, DNOs and final consumers from these proposals.

Our cost benefit analysis suggests that:

- the benefits (in terms of competition impacts and reduced supply costs) could exceed any costs that might be incurred by the DNOs from the options evaluated;
- this result is robust to different assumptions and high level scenarios that have been explored through our cost benefit model; and
- these options would address the issue of network charging volatility and unpredictability within *and* between price control periods.

The volatility and predictability of DNO's future DUoS charges (and network charges more generally) has been an important issue for a number of years.

Given the wider context and changes in retail energy markets and regulatory policy (in particular Ofgem's proposals under the RMR) the interventions we have considered to help provide more predictability and less volatile network charges, could provide relatively simple, cost effective solutions to help address the issues.

We believe this to be an important topic that should be consulted on through a stakeholder driven network price review process.

Based on our analysis, our preferred option at this stage is that a regime similar to that evaluated in this report be adopted for RIIO-ED1, with an emphasis on providing a 15 or 27 month notice period of future DUoS charges between and within price controls. We would welcome feedback on this view as part of a broad consultation process.

ANNEX A: MODELLING

This supporting annex outlines:

- the approach we adopted for modelling the minimum notice period regime, DNO allowed revenue and supplier risk premia;
- the inputs and assumptions adopted in the modelling, including network costs, demand and supplier tariff expectation rules; and
- the detailed results from our modelling scenarios including the cost-benefit analysis, modelled DNO revenue and financeability tests.

A1. Approach

CEPA developed a modelling framework to assess the costs and the benefits of the notice period options in the main report. This was based on modelling the impacts of DUoS charging unpredictability by affected stakeholder groups.

A1.1. DNO modelling

For the DNOs we built a price control financial model using the same approach as the DPCR5 determination. This was extended to include RIIO-ED1 so as to project allowed revenue into the forthcoming price control period (to 2022/23).

The base allowed revenue (set at the price control review) was adjusted based on assumptions of projected revenue adjustments within the price control, for example, from pass-through costs, incentives and RPI inflation. This produced a nominal "actual" DNO allowed revenue.

The price control calculations were also extended to include the possibility of a notice period whereby depending on the length of the notice period, the DNO would make a forecast of future "actual" allowed revenue ahead of when the DUoS charges come into effect.[22]

For the notice period, any forecasting error between the DNO's projected revenue and actual revenue was then added to future years allowed revenue, including any compensation for the DNO for the opportunity cost from changes in the profile of allowed revenue.

The model then completed a financeability check of the impact of providing the notice period on the DNO. This included the impact on gearing and financial ratios and other supporting cash-flow measures (for example, logged up revenue as a percentage of RAV).

The next step in the DNO modelling converted each year of allowed revenue into a set of DUoS charges by customer tariff group. This was achieved by adjusting marginal cost based tariffs from the CDCM models to recover the allowed revenue from the DNO customer base.

[22] We discuss the assumptions we adopted for DNO forecasting in Section A.2.

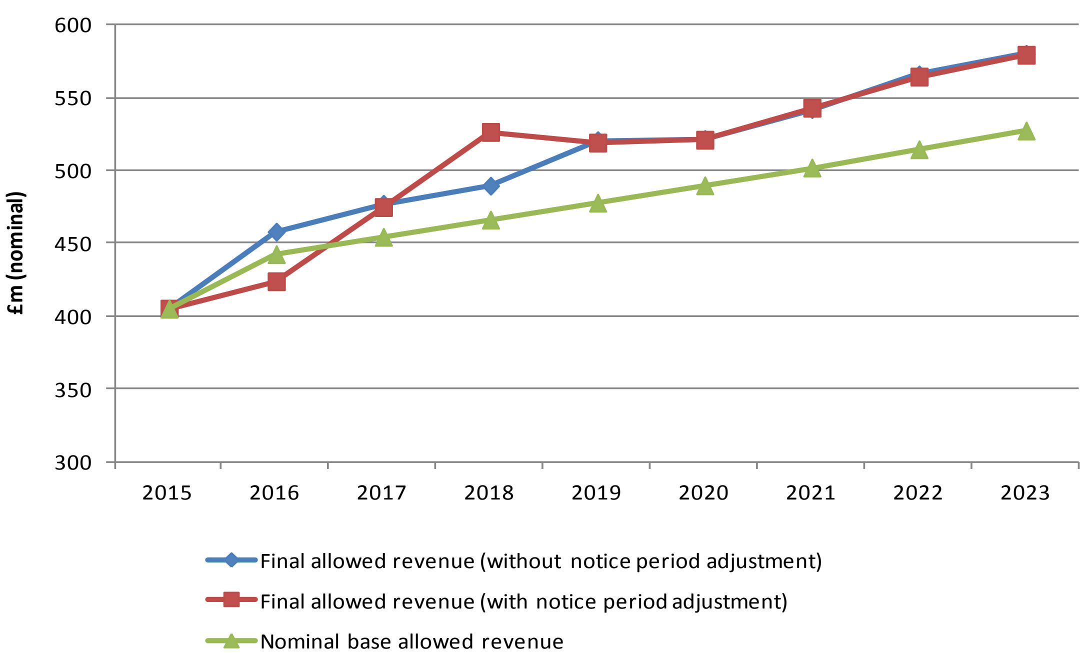
The adjustment of "matching" or "scaling" DUoS charges to recover the projected allowed revenue was applied using the same principles in the DNO CDCM model so that we could be confident of the level and the changes in customer group tariffs from year to year.[23]

The outputs of the DNO modelling were a set of projected DUoS charges which recovered:

- **Revenue Profile 1:** original "base" allowed revenue set according to the building blocks of the price control review (given projected DNO customer demand);
- **Revenue Profile 2:** actual allowed revenue (i.e. revenue including projected adjustments for changes in pass-through costs and incentives etc.) without a notice period; and
- **Revenue Profile 3:** a revised actual allowed revenue set according to the principles of the selected notice period regime.

Taking a 15 month notice period scenario as an example, the green line in Figure A1 is Revenue Profile 1 (base allowed revenue (in nominal terms) set at the time of the price review), the blue line (actual allowed revenue without a DNO notice period) is Revenue Profile 2, while the red line is a reprofiled allowed revenue under the selected notice period regime.

Figure A1: Illustrative scenario allowed revenue profiles



[23] We assumed that the marginal cost based DUoS tariffs (i.e. before revenue matching) and the *proportion* of allowed revenue recovered from DNO customers outside of the CDCM model (i.e. from customers connected to the Extra High Voltage(EHV) level network) remained constant over the modelling period.

A1.2. Supplier modelling

The supplier modelling assessed the impact of unpredictable DUoS charges on electricity suppliers (in terms of network cost recovery from final electricity consumers) by building a portfolio of demand by customer groups.

The number of customers, their load (MWh) and (where relevant) required capacity – and, therefore, supplier DUoS charging incidence by customer group – was equivalent to the the customer demand data that was used to calculate the DNOs DUoS charges.

For each customer group, a fixed proportion of customers were assumed to be on fully variable retail tariffs, one-year, two-year and three-year fixed price retail tariffs (see Section A.2). For:

- customers on variable tariffs, it was assumed any changes in network costs could be passed straight through by suppliers into the retail tariff; but
- for fixed price retail tariffs, forecasts of future DUoS charges made by the supplier would be used to set the network component of the fixed price deal.

The DUoS charges predicted by suppliers for each category of fixed price retail tariff were then based on supplier expectation rules defined as follows:

- An adapative expectation rule where the supplier would use historical information of revenue volatility to set its future retail tariffs.
- A DNO forecasting rule where the supplier would utilise DNO forecasts of future allowed revenue and tariffs to set its future retail tariffs.

Each approach is discussed in the sub-sections which follow.

Adaptive expectation rule

We assumed the supplier is rational, but adopts an adaptive expectation rule for forecasting any changes in DUoS charges from those based on the allowed revenue set at the price control determination (i.e. Profile 1 from Section A.1.1 above).

The supplier adds a forecasting "error term" to the customer group DUoS charge based on the allowed revenue set at the price control determination (i.e. Revenue Profile 1) and historical differences between:

- the DUoS tariff based on price control allowed revenue (i.e. Revenue Profile 1); and
- the DUoS tariff based on actual DNO allowed revenue tariff (i.e. Revenue Profile 2).

Three rules were then tested in the modelling for setting the forecast error term:

- use last year's forecast error term added to the forecast tariff based on the DNOs nominal base allowed revenue;

- a rolling average of the last three year's forecast errors added to the forecast tariff based on base allowed revenue; and
- the weighted average of the last three year's forecast errors is added to the forecast tariff based on base allowed revenue, with more weight being given to recent years.

When having to forecast DUoS tariffs ahead of the base price control allowed revenue being published (i.e. before the final RIIO-ED1 price control determination is published by Ofgem) the model also assumed a supplier would take base allowed revenue in the last year of DPCR5 (adjusted for RPI inflation) as the best available information for pricing terms (although reflecting a business as usual scenario rather than a view of possible changes in allowed revenue).

Formually the supplier's forecasting rule was defined as:

Adapative expectation supplier forecasting rule:

Supplier's expected future DUoS tariff = DUoS tariff based on nominal base allowed revenue (defined at the price control review) + a forecast error term from the past.

Where:

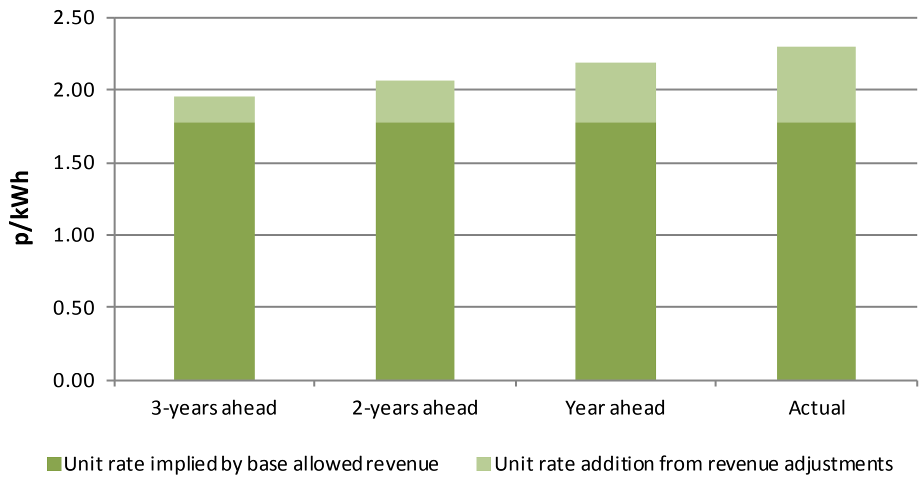
the forecast error in year t = (DUoS tariff based on actual price control allowed revenue – DUoS tariff based on base allowed revenue) for a defined period t-1, t-2, and t-3

DNO forecasting rule

As part of the DCP066 reporting process, the DNOs publish forecasts of actual allowed revenue for the current charging year, 1-year ahead, 2-years ahead and so on. For this forecasting rule, we assumed that the supplier (depending on the duration of the contract price being fixed by the supplier) adopts the latest DNO forecasts of allowed revenue in the relevant charging year.

So for example, as illustrated in Figure A2 below, a supplier having to set a 2-year fixed price contract might have to adopt the DNO's year-ahead or two-year ahead forecasts of actual revenue, and therefore DUoS charges, depending on the timing of when the contract was set relative to when DUoS charges are invoiced by the DNO (see below for further discussion of this issue).

Figure A2: Forecast DUoS unit charges



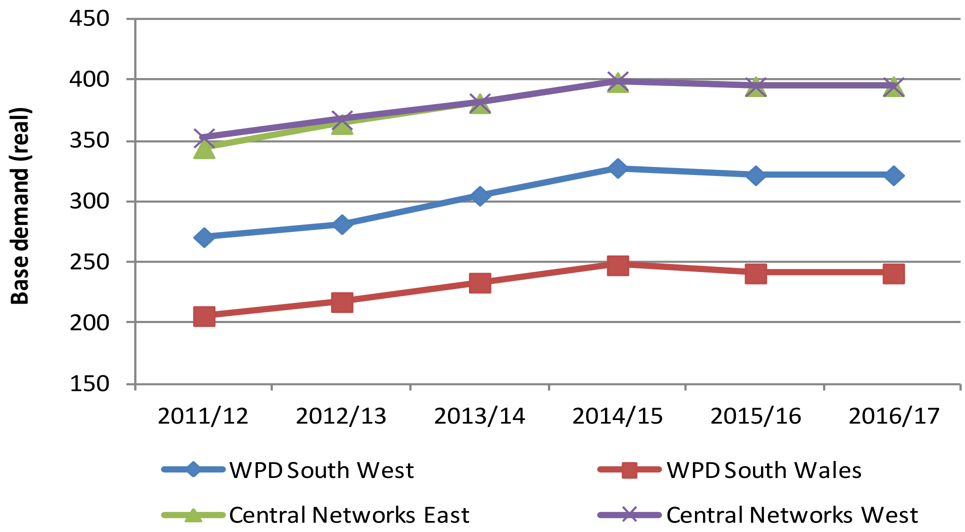
Source: CEPA

This example shows the DNO systematically under forecasting changes in revenue 1-year ahead, 2-years ahead and 3-years ahead. Of course (as discussed in Section 2) it is possible for the DNO to also over forecast future changes in allowed revenue. Under this forecasting rule, this would mean the supplier over recovers its networks costs from its customer base.

As for the adapative expectation rule, the model assumed that to forecast DUoS tariffs ahead of the base price control allowed revenue being published (i.e. before the final RIIO-ED1 price control determination is published by Ofgem) a DNO would publish base allowed revenue in the last year of DPCR5 (adjusted for RPI inflation) which would also be used by the supplier to set its retail tariffs.

Again, while this assumption is based on a business as usual scenario, it is consistent with the information currently available to suppliers through the DCP066 reports. As illustrated in Figure A3 (overleaf) (which reproduces Figure 2.4 from Section 2) many of the DNOs are currently publishing a no change scenario for their revenue forecasts into RIIO-ED1.

Figure A3: Base demand revenue forecasts



Source: CEPA

Constructing the supplier risk premia

The money actually recovered from each customer demand group for network costs, based on the supplier forecast or predicted DUoS charges, was then compared to the actual DUoS charges paid by the supplier (based on the actual DNO revenue allowed under the price control). Any difference between these amounts was used to calculate an "implied" risk premium.

So for example, in the case of variable retail tariff groups, where there is full cost pass through of distribution network costs, the DNO and supplier recovered DUoS charges were the same and there was no implied risk premium. Where a supplier had to predict the DUoS charge and this was lower than the actual DUoS charge, this was an implied risk premium.

Formually this was defined as:

Supplier risk premia:

Supplier risk premia (by customer group n) = ((Supplier recovered network costs in £s from retail customers – Actual network costs paid to the DNO in £s)/ Actual network costs paid to the DNO in £s)*100

Where:

n is the DUoS customer group (for example, domestic unrestricted, domestic two-rate, small non-domestic unrestricted, LV HH Metered etc.)

Where:

∑ of supplier risk premia across all DUoS customer groups (n) is the total risk premia for the supplier contract porfolio.

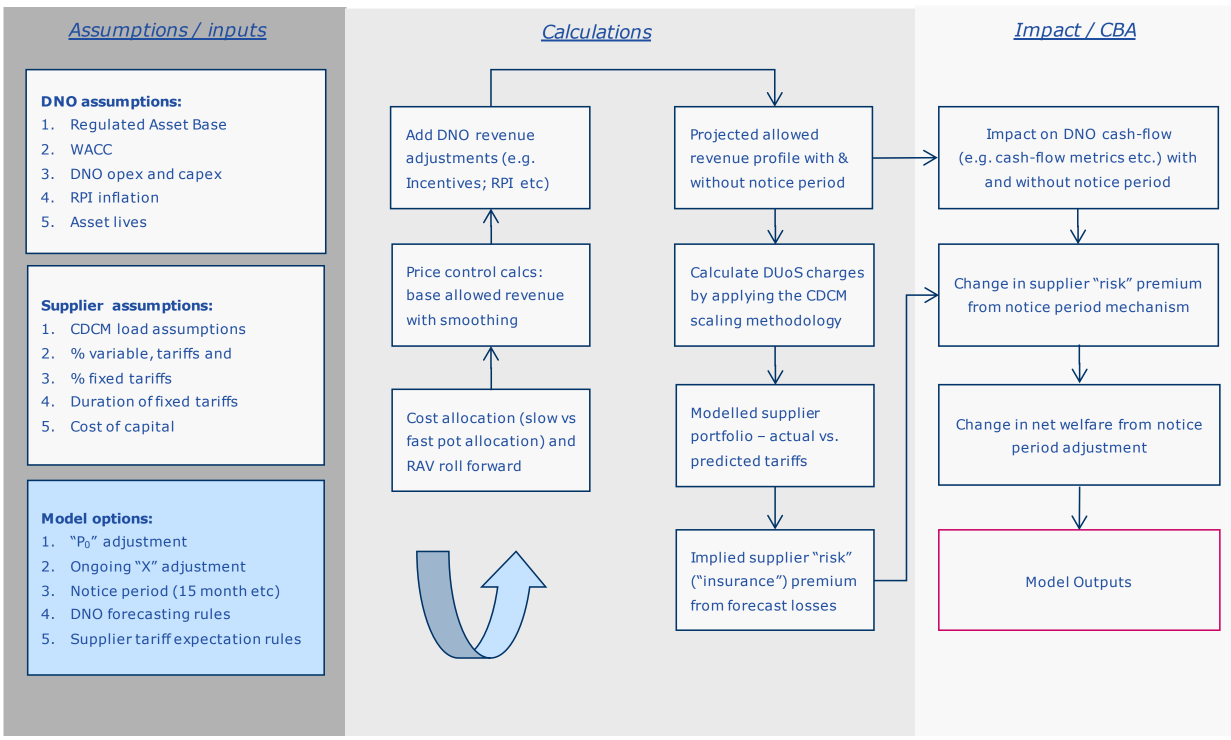
A1.3. Cost-benefit analysis

The costs and benefits of each of the notice period regimes were presented from the perspective of the final consumer, measured against a "base case" scenario where there is no notice period regime. The costs and benefits were calculated annually and as a Net Present Value (NPV) for the eight years of RIIO-ED1 (using the Green Book real discount rate of 3.5%).

A1.3. Summary

Figure A4 illustrates how each element of the modelling comes together.

Figure A4: Model diagram



A2. Assumptions

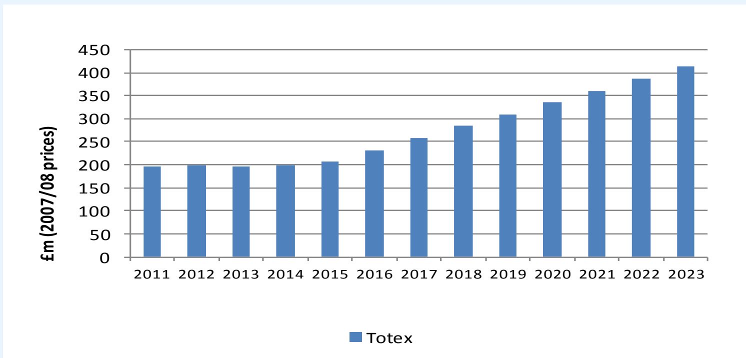
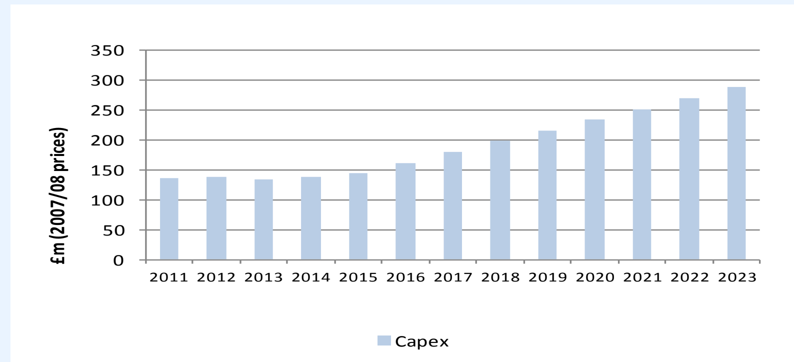
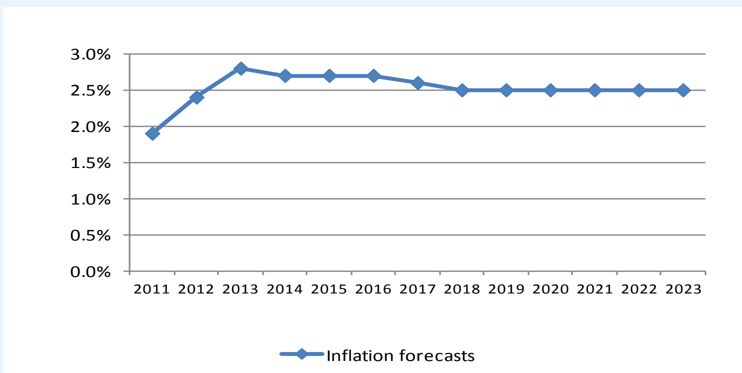
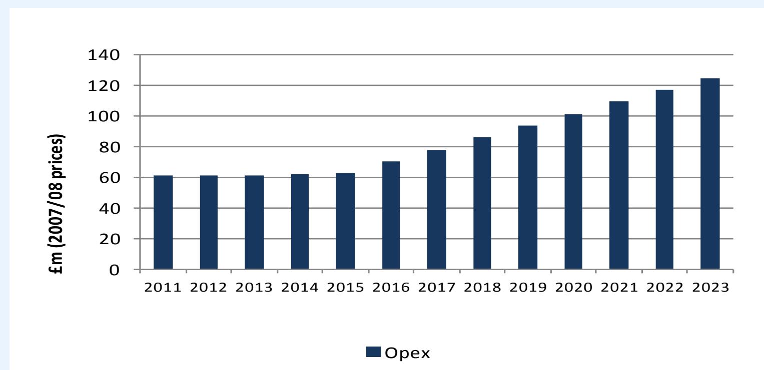
This section presents the assumptions we have used to develop an "average" model DNO. This includes customer load assumptions, CDCM inputs and projected price control costs.

We also describe the different revenue smoothing approaches adopted in the modelling including the DPCR5 approach of adopting a constant percentage increase each year.

A2.1. DNO costs

Table A1 illustrates the capex and opex profiles adopted in the modelling. These are based on an "average" DNO rolled forward from the DPCR5 determination.

Table A1: Projected DNO costs

Total expenditure (totex) projections:	Capex projections:
	
Inflation forecasts:	**Opex projections:**
	

Notes: Inflation forecasts are consistent with those used in the DPCR5 financial model. RPI inflation is assumed to be a variable known with certainty by all stakeholder groups rather than an assumption being made on supplier and DNO forecast RPI compared to actual outturn RPI.

A2.2. Regime and financial assumptions

Table A2 shows the regime and financial assumptions adopted in the modelling for DPCR5 and RIIO-ED1.

Table A2: Regime assumptions

Parameter	DPCR5	RIIO-ED1
WACC	4.685%	4.685%
Cost of debt	3.60%	3.60%
Notional gearing	65%	65%
Taxation rate	28%	24%
Tax	DNO specific allowance	DNO specific allowance
Asset lives (years) existing assets	20	20
Asset lives (years) new assets	n/a	45
Fast/slow money split	15:85	15:85

Assumptions for capitalisation allocations and rates by asset group were based on an "average" DNO as sourced from the DPCR5 financial model.

A2.3. Revenue smoothing and profiling

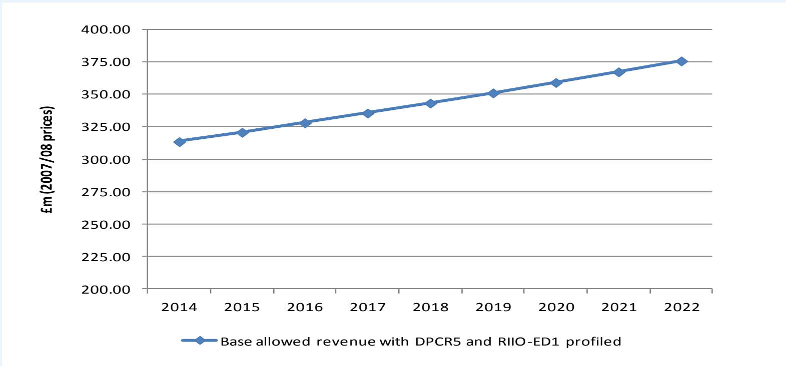
The model calculates different Revenue Profiling scenarios based on different P_0 and ongoing X revenues assumptions. For example, a "step change" in revenues (through a P_0 adjustment) versus a "gradual change" in projected allowed revenues.

The final proposals for DPCR5 decided that the allowed revenue increases would be smoothed over the 2010-2015 period to achieve a constant percentage increase each year (while recovering the same total revenue in Present Value terms). The same revenue smoothing approach has also been applied for our "average" DNO.

Table A3 (overleaf) illustrates the price control revenue smoothing and profiling assumptions tested in the modelling for RIIO-ED1.

Table A3: Revenue profiling

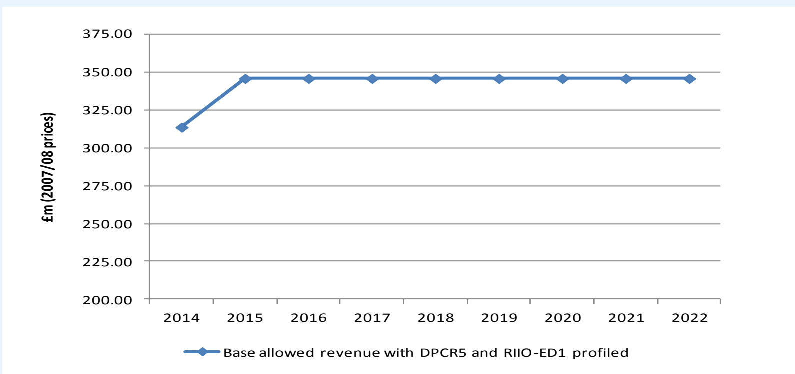
Constant "X" percentage increase



Revenue profiling adjustment:

2007/08 price base		Current scenario
Price control impacts	P0 adjustment at the start of RIIO-ED1	2.3%
	Annual "X" adjustment over RIIO-ED1	2.3%

P0 adjustment (+ %) with "X" = 0



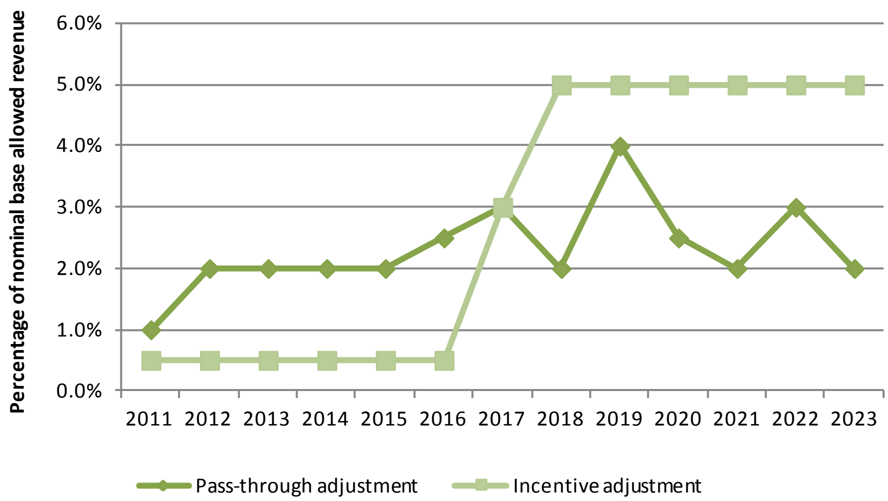
Revenue profiling adjustment:

2007/08 price base		Current scenario
Price control impacts	P0 adjustment at the start of RIIO-ED1	10.2%
	Annual "X" adjustment over RIIO-ED1	0.0%

A2.4. Revenue adjustment volatility

The model adopted stylised assumptions for revenue volatility caused by incentives, pass-through costs and other adjustment factors. These were expressed as a percentage of nominal base allowed revenue with assumptions developed based on the analysis of historical volatility and future volatility presented in Section 2. Figure A5 illustrates our assumptions.

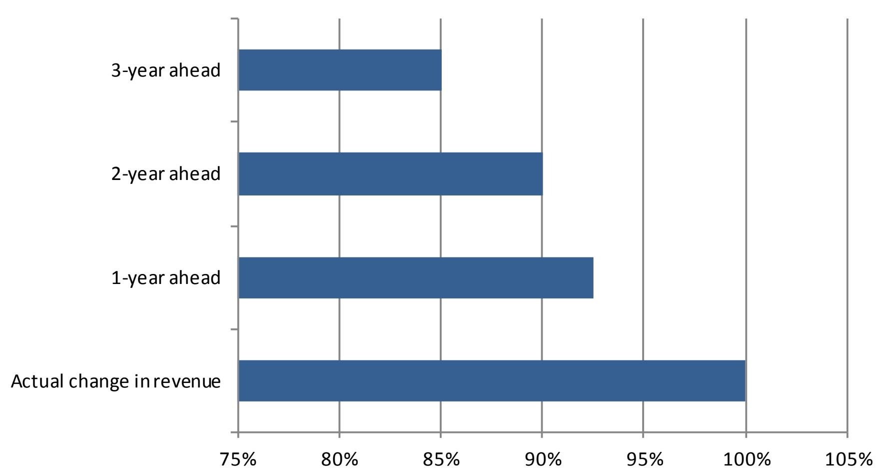
Figure A5: Revenue adjustments



A2.5. DNO forecasting error

The model assumed the DNO systematically *under forecasts* future changes in allowed revenue. The assumptions adopted for the errors in the DNO's 1-year, 2-year and 3-year ahead forecasts are illustrated in Figure A6.

Figure A6: DNO forecasting error



A2.6. Contract portfolio assumptions

For each DUoS charging group a fixed proportion of the demand in on Table A4 was assumed to be on different retail contract durations:

- Variable customer contracts were assumed to have full network cost pass-through (and therefore no supplier risk premium); while
- Fixed customer contracts (whether a 1-year, 2-year or 3-year fix) required a forecast of future network costs and therefore carried a risk for suppliers.

Table A5 illustrates the assumptions adopted by customer group. These percentages remained fixed for each year of the modelling.

Table A5: Contract duration assumptions

Variable (full network cost pass-through)

Percentage on variable tariffs	%
Domestic Unrestricted	40%
Domestic Two Rate	40%
Domestic Off Peak (related MPAN)	40%
Small Non Domestic Unrestricted	10%
Small Non Domestic Two Rate	10%
Small Non Domestic Off Peak (related MPAN)	10%
LV Medium Non-Domestic	0%
LV Sub Medium Non-Domestic	0%
HV Medium Non-Domestic	0%
LV HH Metered	0%
LV Sub HH Metered	0%
HV HH Metered	0%
HV Sub HH Metered	0%
NHH UMS	0%
LV UMS (Pseudo HH Metered)	0%

2-year fix

Percentage on 2-year fixed price contracts	%
Domestic Unrestricted	15%
Domestic Two Rate	15%
Domestic Off Peak (related MPAN)	15%
Small Non Domestic Unrestricted	20%
Small Non Domestic Two Rate	20%
Small Non Domestic Off Peak (related MPAN)	20%
LV Medium Non-Domestic	25%
LV Sub Medium Non-Domestic	25%
HV Medium Non-Domestic	25%
LV HH Metered	25%
LV Sub HH Metered	25%
HV HH Metered	25%
HV Sub HH Metered	25%
NHH UMS	25%
LV UMS (Pseudo HH Metered)	25%

1-year fix

Percentage on 1-year fixed price contracts	%
Domestic Unrestricted	40%
Domestic Two Rate	40%
Domestic Off Peak (related MPAN)	40%
Small Non Domestic Unrestricted	50%
Small Non Domestic Two Rate	50%
Small Non Domestic Off Peak (related MPAN)	50%
LV Medium Non-Domestic	50%
LV Sub Medium Non-Domestic	50%
HV Medium Non-Domestic	50%
LV HH Metered	50%
LV Sub HH Metered	50%
HV HH Metered	50%
HV Sub HH Metered	50%
NHH UMS	50%
LV UMS (Pseudo HH Metered)	50%

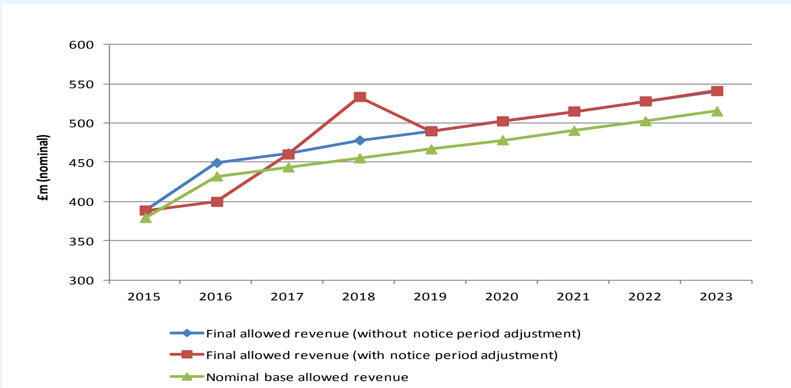
3-year fix

Percentage on 3-year fixed price contracts	%
Domestic Unrestricted	5%
Domestic Two Rate	5%
Domestic Off Peak (related MPAN)	5%
Small Non Domestic Unrestricted	20%
Small Non Domestic Two Rate	20%
Small Non Domestic Off Peak (related MPAN)	20%
LV Medium Non-Domestic	25%
LV Sub Medium Non-Domestic	25%
HV Medium Non-Domestic	25%
LV HH Metered	25%
LV Sub HH Metered	25%
HV HH Metered	25%
HV Sub HH Metered	25%
NHH UMS	25%
LV UMS (Pseudo HH Metered)	25%

A3. Scenario results

Table A6: Scenario 1 and 3 allowed revenue outputs under notice period durations

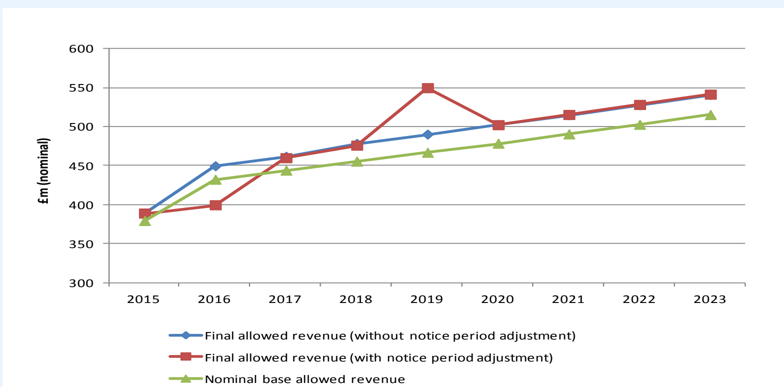
DNO allowed revenue – 15 month notice period



DNO cash-flow metrics

Cash-flow impacts of notice period		£m nominal		
		15 month	27 month	39 month
DNO impacts	Logged up revenue from notice period	66.2	76.4	93.6
	DNO cost of funding notice period	8.7	14.6	23.0
	Revenue recovered post RIIO-ED1	4.3	9.0	19.1

DNO allowed revenue – 27 month notice period



DNO allowed revenue – 39 month notice period

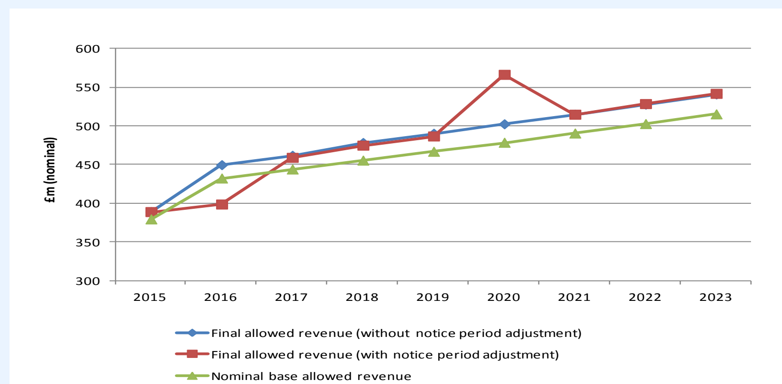
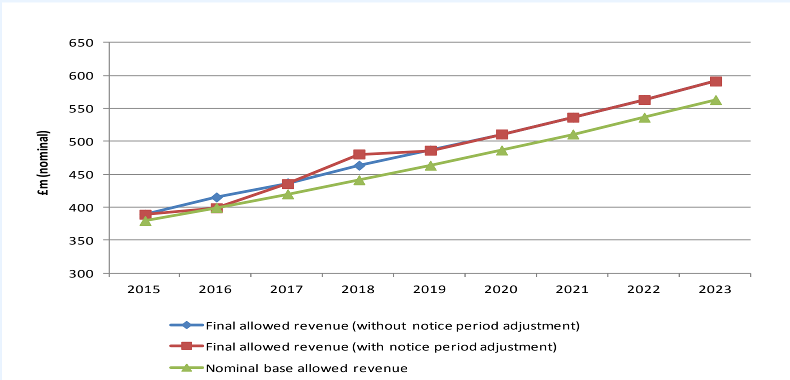


Table A7: Scenario 2 and 4 allowed revenue outputs under notice period durations

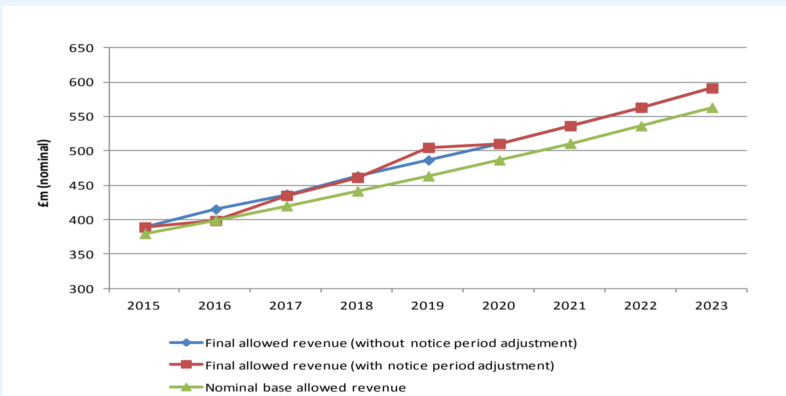
DNO allowed revenue – 15 month notice period



DNO cash-flow metrics

Cash-flow impacts of notice period		£m nominal		
		15 month	**27 month**	**39 month**
DNO impacts	Logged up revenue from notice period	31.6	39.3	53.9
	DNO cost of funding notice period	4.2	7.5	13.3
	Revenue recovered post RIIO-ED1	4.6	9.6	20.1

DNO allowed revenue – 27 month notice period



DNO allowed revenue – 39 month notice period

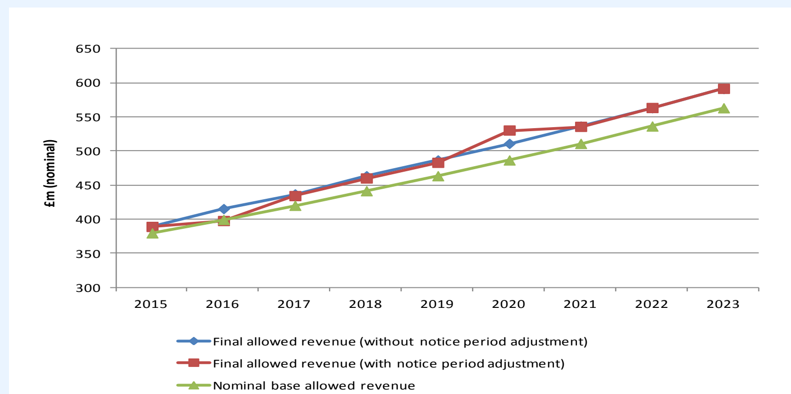


Table A8: Outputs of the cost benefit analysis for each model scenario

Scenario 1 – results of CBA

Cost benefit analysis		NPV £m nominal		
		15 month	27 month	39 month
Consumer welfare	Reduction in supplier costs managing volatility	33.2	49.1	63.0
	DNO costs managing volatility	-8.2	-13.6	-21.3
	Change in net consumer welfare from notice period	25.0	35.5	41.8

Scenario 2 – results of CBA

Cost benefit analysis		NPV £m nominal		
		15 month	27 month	39 month
Consumer welfare	Reduction in supplier costs managing volatility	21.9	32.5	42.1
	DNO costs managing volatility	-3.8	-6.8	-11.8
	Change in net consumer welfare from notice period	18.1	25.8	30.3

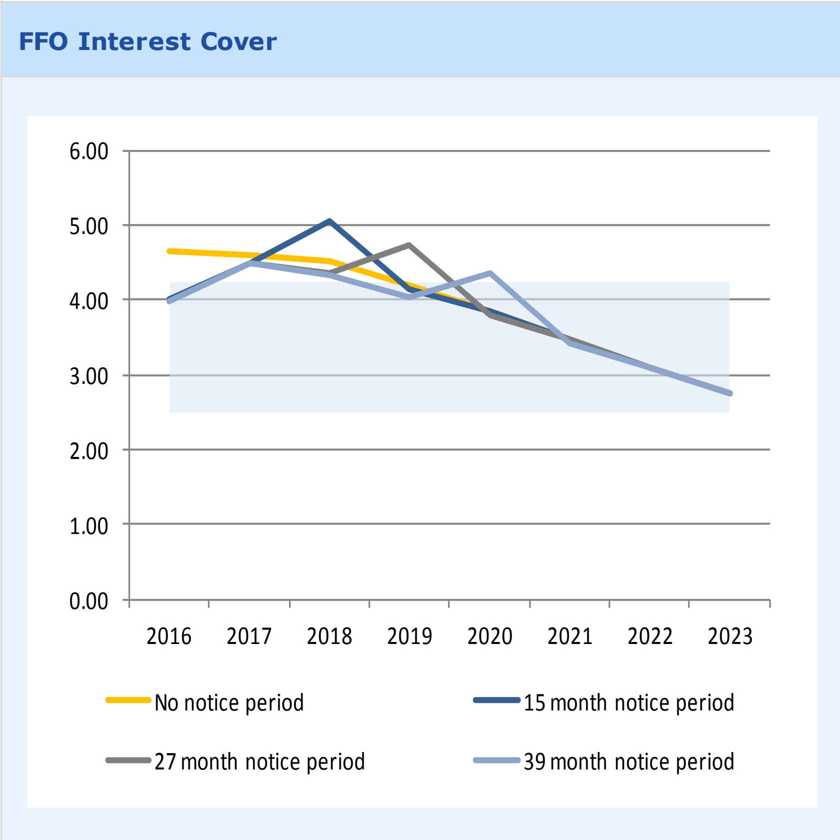
Scenario 3 – results of CBA

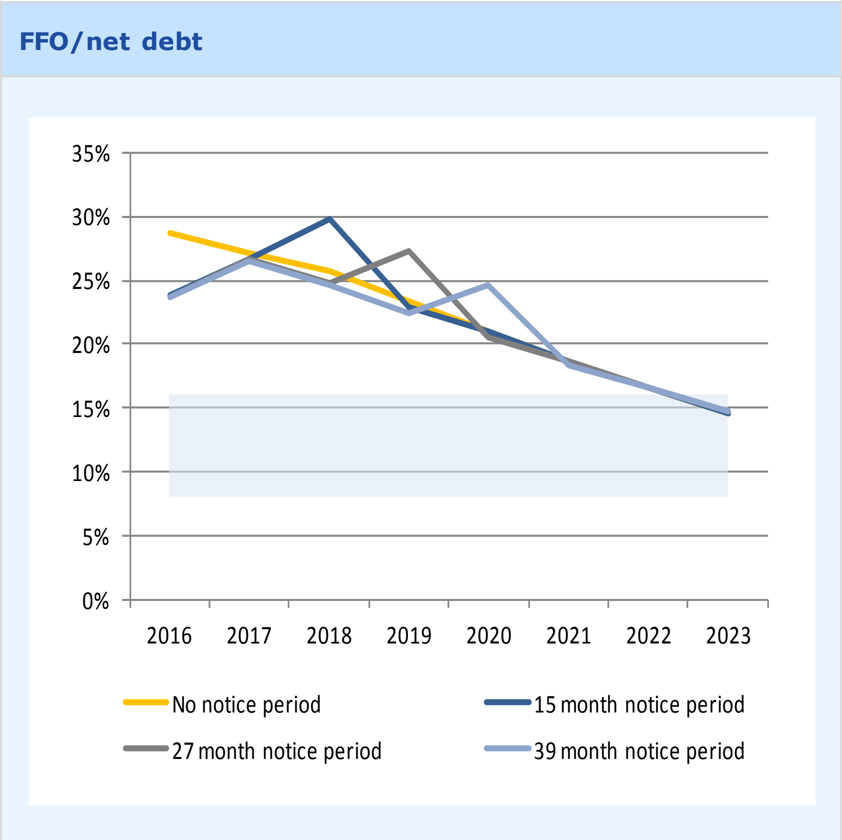
Cost benefit analysis		NPV £m nominal		
		15 month	27 month	39 month
Consumer welfare	Reduction in supplier costs managing volatility	45.4	46.6	47.7
	DNO costs managing volatility	-8.2	-13.6	-21.3
	Change in net consumer welfare from notice period	37.2	33.0	26.5

Scenario 4 – results of CBA

Cost benefit analysis		NPV £m nominal		
		15 month	27 month	39 month
Consumer welfare	Reduction in supplier costs managing volatility	21.9	23.2	24.3
	DNO costs managing volatility	-3.8	-6.8	-11.8
	Change in net consumer welfare from notice period	18.1	16.4	12.5

Table A9: Ratio analysis – scenario 1 and 3

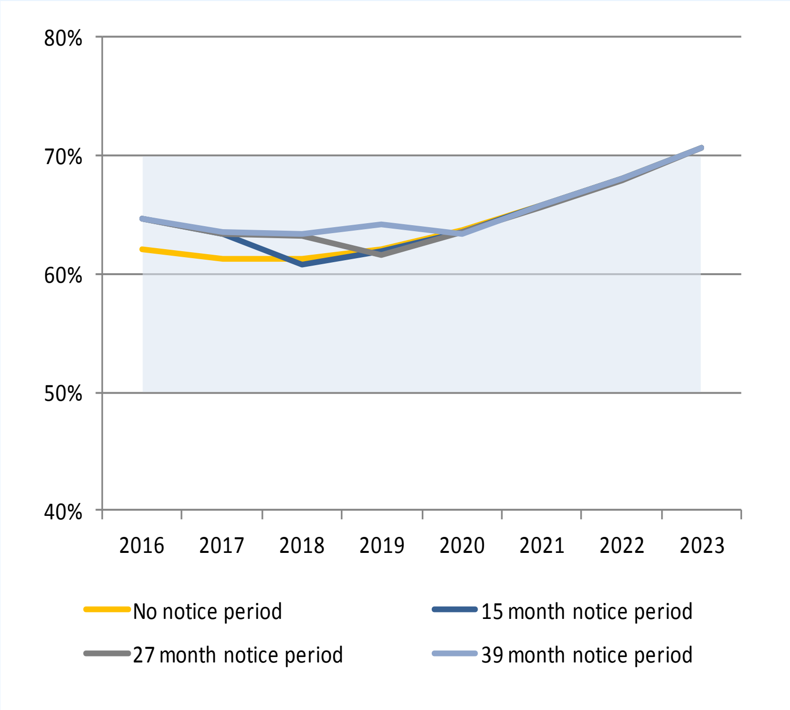




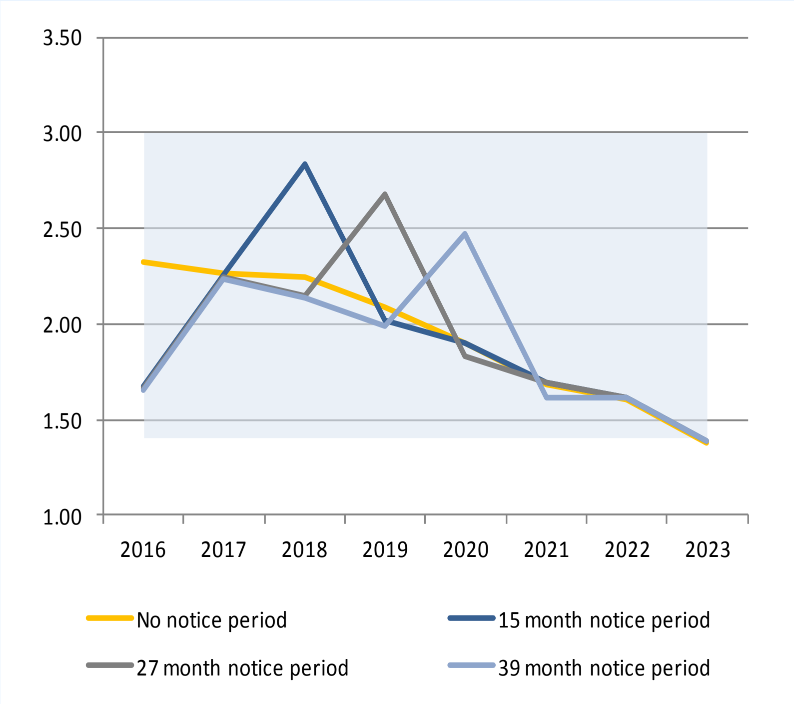
Note: shaded area denotes target range for financeability ratio; if the financeability ratio goes below the shaded area then the financeability ratio test is failed.

Table A10: Ratio analysis – scenario 1 and 3

Gearing



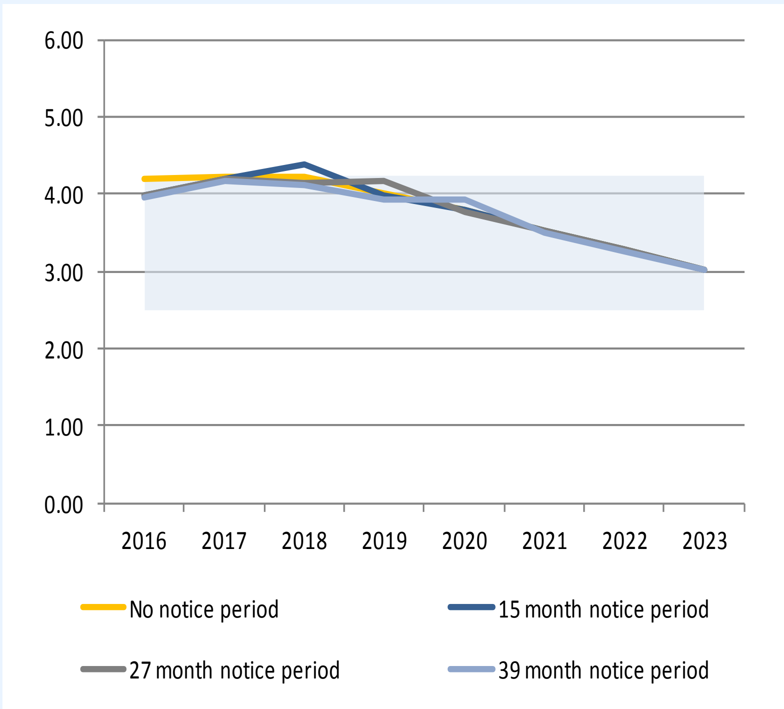
PMICR



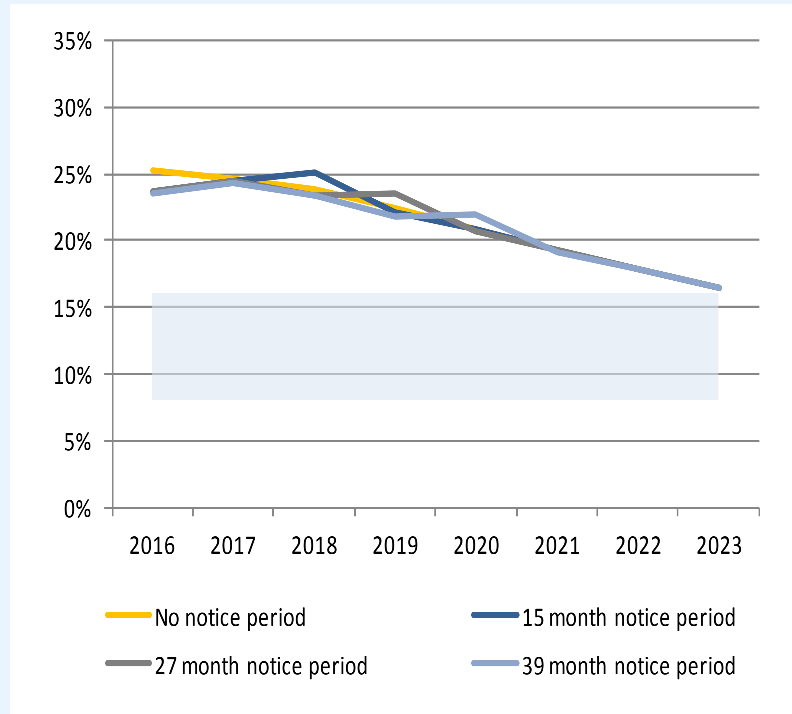
Note: shaded area denotes target range for financeability ratio; if the financeability ratio goes below the shaded area then the financeability ratio test is failed. The exception to this is gearing where the financeability test is gearing below 70%.

Table A11: Ratio analysis – scenario 2 and 4

FFO Interest Cover



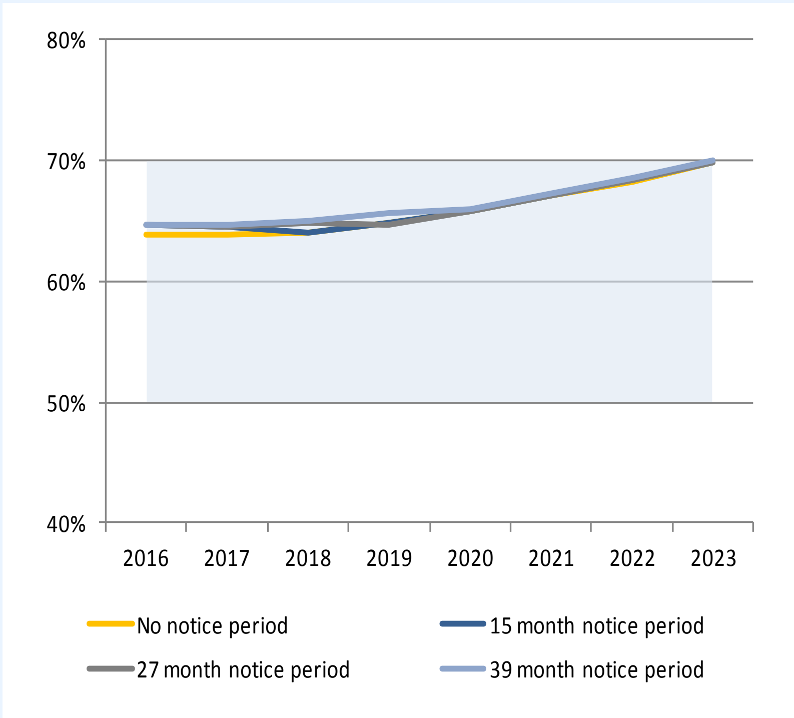
FFO/net debt



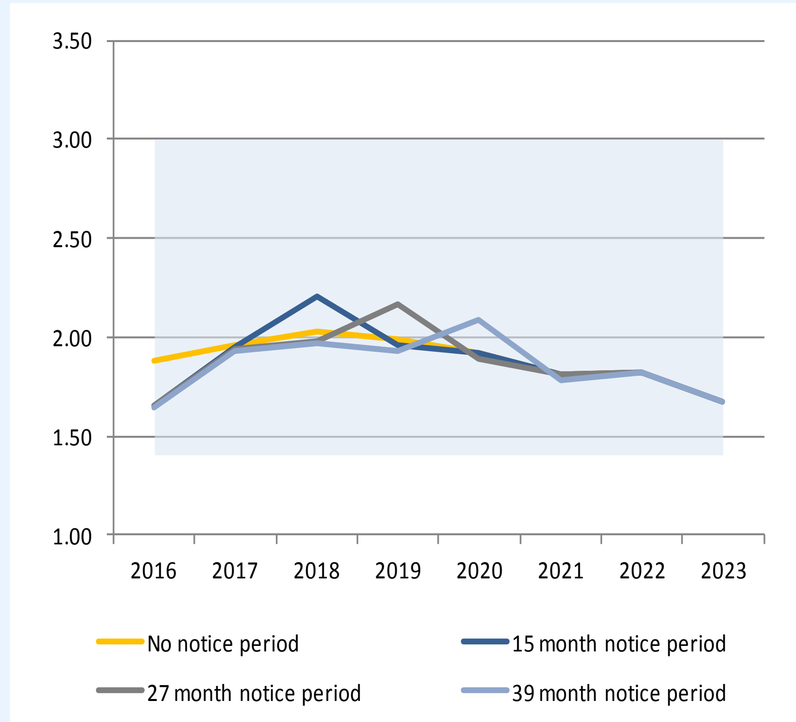
Note: shaded area denotes target range for financeability ratio; if the financeability ratio goes below the shaded area then the financeability ratio test is failed.

Table A11: Ratio analysis – scenario 2 and 4

Gearing



PMICR



Note: shaded area denotes target range for financeability ratio; if the financeability ratio goes below the shaded area then the financeability ratio test is failed. The exception to this is gearing where the financeability test is gearing below 70%.