Utility Regulator
www.uregni.gov.uk

Power NI Supply
Price Control 2026-2029
Final Determination

Final Determination
24 April 2025

About the Utility Regulator

The Utility Regulator is the independent non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries, to promote the short and long-term interests of consumers.

We are not a policy-making department of government, but we make sure that the energy and water utility industries in Northern Ireland are regulated and developed within ministerial policy as set out in our statutory duties.

We are governed by a Board of Directors and are accountable to the Northern Ireland Assembly through financial and annual reporting obligations.

We are based at Queens House in the centre of Belfast. The Chief Executive and two Executive Directors lead teams in each of the main functional areas in the organisation: CEO Office; Price Controls; Networks and Energy Futures; Markets; Consumer Protection and Enforcement. The staff team includes economists, engineers, accountants, utility specialists, legal advisors and administration professionals.

OUR MISSION

To protect the short and long-term interests of consumers of electricity, gas and water.

OUR VISION

To ensure value and sustainability in energy and water.

OUR VALUES

ACCOUNTABLE
We take ownership of our actions.

TRANSPARENT
Ensuring trust through openness and honesty.

COLLABORATIVE
Connecting and working with others for a shared purpose.

DILIGENT
Working with care and rigour.

RESPECTFUL
Treating everyone with dignity and fairness.

Abstract

This paper sets out Utility Regulator's (UR) final determination for the next Power NI Supply Price Control, which covers a four-year period from April 2025 to March 2029.

The Power NI Supply Price Control sets out the revenue Power NI will be allowed to recover to run its business and the basis for calculating of the average maximum allowed unit price of electricity Power NI can charge regulated (domestic) consumers.

The focus of the final determination and the proposed licence modifications is operating expenditure, margin and any other pass-through costs which Power NI can recover from consumers.

Audience

Power NI, consumers, consumer representatives, consumer groups, other regulated companies in the energy industry, government, and other bodies with an interest in the energy industry.

Consumer impact

Power NI is the only electricity supplier in Northern Ireland whose domestic tariffs are regulated. The price control sets allowed values for the costs and margin for the duration of the control period and subsequent regulated tariffs will be set using these determined values and the mechanisms of the licence. The price control decisions have an impact on about 8% of an average domestic bill.

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Executive Summary

This paper sets out the Utility Regulator's (UR's) final determination for the next Power NI Supply Price Control (SPC25), which will regulate the maximum tariff Power NI can charge its domestic electricity consumers during the four-year period from 1 April 2025 to 31 March 2029.

We have followed a robust and thorough process in coming to our final decisions. This process began in early 2024 and involved extensive engagement with Power NI and careful consideration of its Business Plan and margin submissions. We have publicly consulted on both our approach to the price control and our draft determination. We have carefully considered and taken into account the two responses received to our draft determination consultation and all additional information provided by Power NI.

The focus of our final determination is the amount of operating and other costs which Power NI can recover to run its business and the margin it can recover to finance its activities. Based on the most recent Power NI tariff review, which covers a 2-year period from December 2024, these costs make up 8% of a typical domestic electricity bill.

Scope and coverage of the Price Control

At present, Power NI is subject to a Price Control in the Northern Ireland (NI) domestic electricity supply market. The SPC25 Price Control will continue the regulation of the maximum tariff Power NI can charge domestic consumers for the supply of electricity. It is designed to have effect as from 1 April 2025 and the pre-existing arrangements for regulated tariffs will therefore cease to be in effect as from the end of 31 March 2025.

Power NI is the sole electricity supplier in Northern Ireland whose domestic electricity tariffs are regulated. It currently supplies 61% of domestic consumers in the NI market. Its market share has risen over the last four years and the company has assumed an increasing market share over the next four years in its business plan submission for SPC25. Because the company continues to have a dominant position in the domestic electricity market, we have decided that it remains in the interest of consumers to continue to regulate the maximum average charge per unit it supplies to regulated (domestic) premises.

Duration of the Price Control

The Price Control period will be set for four years from 1 April 2025 to 31 March 2029. This will reduce the regulatory burden of shorter Price Controls on both the company and the regulator. It will also allow for a period of stability as the electricity sector develops to support decarbonisation of the economy.

Structure and form of the Price Control

We are maintaining much of the structure and form of previous price controls, but are also introducing amendments where we have determined these to be in the interest of consumers.

The structure of the price control allows Power NI to recover, by passing through domestic consumers, much of the actual cost of supplying electricity to those consumers. This includes the costs of the purchase of energy, networks charges, market operator charges, and renewable obligation charges. The company forecasts these costs when it sets tariffs and then recovers (or returns to consumers) the difference its forecast and its actual costs the next time it resets tariffs. This ability to reset tariffs periodically to reflect actual historical costs is a significant risk mitigation factor for the company, allowing it to make good any earlier under-recovery arising from its forecast costs being less than the actual costs allowable.

For SPC25, we have proposed two material changes to the structure and form of the price control:

- We have introduced a cost sharing mechanism whereby Power NI will retain 35% of any savings and absorb 35% of any over-run compared to determined costs for operating expenditure (Opex). This will return cost savings to consumers more quickly and will protect both consumers and the company from changes in costs over a four-year price control period.

- We have introduced a mechanism to vary the margin in relation to customer numbers and the market price of energy to protect both Power NI and consumers against changing circumstances in energy markets outside the control of the company. The mechanism provides significant protection for the company as energy prices increase, but could result in a very low level of margin if energy prices fall significantly. Therefore, we have added a floor price of energy – i.e. a minimum price which will be used for the purposes of the margin calculation – which will protect the company's margin if such a significant fall occurs.

Operating expenditure (Opex)

UR conducted a robust analysis of Power NI operating costs which include expenditure such as salaries, IT costs, bad debt, shared services, and materials and bought in services. We determined that Power NI's forecast of future costs are mainly reasonable but have made a reduction to the company's requested operational costs of 2%. Table 1 below shows UR's final determination for the Opex amounts for the duration of the SPC25 Price Control in October 2023 prices.

Cost Category	UR DETERMINED COSTS (£m)			
	FY26	FY27	FY28	FY29
Determined Opex	40.543	40.802	39.629	39.788
Determined depreciation	1.163	0.972	0.849	0.818
Determined Opex and depreciation	**41.706**	**41.774**	**40.478**	**40.606**

Table 1: UR Proposed OPEX and other costs for FY26-FY29

Operating expenditure allocation

The final determination of operating costs and other costs covers the operation of the Power NI domestic and commercial businesses and certain other group activities. The Price Control includes a methodology for allocating these determined costs between the different parts of Power NI's activities so that the determination of domestic tariffs only takes account of costs relevant to the domestic business. In the recent past, the allocation of these determined costs to other parts of the Power NI business has been in the range of 22-24%. For the SPC25 Price Control, we reviewed the existing methodology and intend to continue the methodology and cost drivers that have been in use prior to SPC25.

Margin review

We have determined a margin which the company can recover to finance its activities of £16.5m (£15.3m in October 2023 prices), equivalent to a margin of approximately 2.2% of revenues. This compares to the revised amount proposed by the company in its response to the draft determination of £29.6m.

The difference between the value of UR's determined margin and that proposed by the company flows from a difference in the respective methodologies we have each used to determine the margin.

- First, we have a different view of the risk faced by the company which is reflected in the calculation of the cost of equity. Power NI argues that the risk faced by its business is almost equivalent to the risks faced by an electricity supply company working in a fully competitive market in GB. We consider that the various protections inherent in the licence, such as the full recovery of energy, network and market costs, significantly mitigate the commercial risks faced by the company so that there is no real comparison with GB.

- Secondly, Power NI has put forward a margin based on a stand-alone company, without regard to the way the company is currently financed. We have concluded that our final determination should be based on the individual circumstances of the regulated company, taking account of the facts as they are known to UR at the time this decision falls to be made. This difference in approach affects the amount of the capital requirement that might reasonably be expected to be financed through contingent capital, such as letters of credit or parent company guarantees posted as collateral, as opposed to direct cash investment.

The determination of margin is linked to a market price of energy of £150/MWh (£139/MWh in October 2023 prices) which the company used when it developed its business plan. However, there has been significant variation in the market price for energy in recent years. The average monthly price in the Day Ahead Market on the island of Ireland peaked at £327/MWh in August 2022, but since March 2023 it has remained below £150/MWh with a minimum of £72/MWh. Because variability is driven by external events and is not predictable, we have introduced a mechanism to vary the margin by reference to the market price of energy, subject to a floor price (below which the market price of energy will not fall for the purposes of the margin calculation).

Next steps

In parallel with the publication of this final determination, we have published a consultation on the licence modifications necessary to give effect to our decisions. This licence modification consultation will close on 23 May 2025. We intend to publish a final decision on licence modifications at the end of June 2025. The licence modifications will come into effect by 25 August 2025, subject to the right of Power NI to appeal our final decision on licence modifications to the Competition and Markets Authority (CMA). In any event, the modifications will be treated as being applicable with effect on and from 1 April 2025. We will continue to monitor delivery, and engage as we always do in a process of continuous improvement, which will inform the development of our next price control for Power NI, namely SPC29.

1. Introduction

1.1 This paper sets out UR's final determination for the next Power NI Supply Price Control (SPC25), which will regulate the maximum tariff Power NI can charge its domestic electricity consumers during the four-year period from 1 April 2025 to 31 March 2029.

1.2 In December 2024, we published a consultation on our draft determination for SPC25. Having considered the responses to that consultation, we are now publishing a final determination. At the same time, we are publishing a consultation on the modifications we propose to make to the Power NI licence to give effect to the decisions set out in this final determination.

1.3 Having considered the response to this consultation on the licence modifications, we intend to publish our final decision on the licence modifications at the end of June 2025. The modifications will take effect by the end of August unless they are subject to an appeal to the Competition and Markest Authority (CMA). However, the nature of the modified price control is such that the modifications will be treated as being applicable on and from 1 April 2025.

1.4 While this final determination deals with all aspects of the Power NI Price Control, its focus is the determination of Power NI's operating costs, other costs and margin. These costs make up about 8.4% of a typical domestic electricity bill.

Strategic context for SPC25

1.5 In the electricity sector, the principal objective of UR is "to protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity"[1].

1.6 Following a three-year Price Control in 2014, recent Power NI Price Controls (2019-2021, 2021-2023 and 2023-2025) have covered two-year periods and on each occasion broadly extended the pre-existing regulatory arrangements. However, the most recent price control included a two-year agreement to allow Power NI to recover the difference between allowances and actual costs at a time when costs had increased significantly. This most recent current price control review ended on 31 March 2025 and the SPC25

[1] Article 12(1) of the Energy (Northern Ireland) Order 2003

Price Control modifications will be treated as being applicable with effect on and from 1 April 2025.

1.7 Power NI developed from the incumbent monopoly supplier at the time supply competition was introduced, and therefore had a dominant market position at the outset. Over time competition has increased. The electricity supply market in Northern Ireland is now served by nine competing supply companies, of which seven are active in the domestic market. Most of these businesses also supply industrial and commercial (I&C) customers. At present, there are approximately 849,000 consumers served by the domestic electricity market and approximately 77,000 in the I&C market. Power NI currently supplies 60.9% of the domestic market and 48.4% of I&C market (by connections). It continues to have a dominant position in the domestic supply market. When competition is not sufficiently developed or effective, UR ensures that the interests of consumers are protected by regulation, and this price control therefore continues to regulate the maximum regulated tariff charged by Power NI to domestic consumers.

1.8 Electricity suppliers in Great Britain (GB) and the Republic of Ireland (ROI) are not subject to Price Controls as the markets in these areas are significantly more competitive than the market in Northern Ireland (NI).

Consumer impact

1.9 A large proportion of the costs which make up the tariffs that Power NI can charge (for example, the commodity cost of electricity supplied, network charges and buyout of renewable obligations) are determined only when the cost of these elements can be properly assessed. The Price Control sets the mechanisms by which these costs may be determined and recovered from consumers and includes financial values which set the operating costs and margin that Power NI is entitled to recover for the activity of supplying electricity to domestic consumers. As an indication of the immediate impact of these determinations, the value of operating costs and margin determined for the SPC25 Price Control (FY26-FY29) is 8.4% of a typical domestic bill per annum based on an average consumption of 3,200 kWh. This percentage remains relatively unchanged compared to the pre-existing price control. Currently the average annual bill from 1 December 2024 is £989 inclusive of VAT with a unit price of 29.44 p/kWh ex VAT or 30.91 p/kWh incl. VAT[2].

1.10 The primary purpose and effect of this Price Control is to continue to ensure that, despite the dominant position of Power NI in the NI domestic electricity supply market, the company charges its domestic customers a fair price for

[2] Conclusion of the Utility Regulator's Review of the Power NI Ltd Maximum Average Price Effective 1 December 2024

electricity while also having sufficient resources to be able to finance its activities and provide high quality customer service.

Our statutory duties

1.11 Our principal objective and statutory duties in relation to the exercise of our electricity functions (including setting the Power NI Price Control) are set out fully at Article 12 of the Energy (Northern Ireland) Order 2003 (the Energy Order)[3]. These include objectives which we must aim to achieve, definitions, duties, and a number of matters to which we must have regard. For ease of reference, we summarise the main elements of Article 12 below, but like any summary it is not entirely complete. We have referred to the full text of the Article and associated definitions, as these are what we have relied upon in reaching our draft and final determinations.

1.12 Our principal objective in carrying out our electricity functions is to protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity. Consumers, for this purpose, means both existing and future consumers.

1.13 We must carry out those functions in the manner which we consider is best calculated to further the principal objective, having regard in particular to:

a) The need to secure that all reasonable demands in Northern Ireland or Ireland for electricity are met.

b) The need to secure that licence holders are able to finance the activities which are the subject of obligations imposed by or under Part II of the Electricity (Northern Ireland) Order 1992 (the Electricity Order) or the Energy Order.

1.14 We must also carry out our functions consistently with a number of other duties which are set out in full at Article 12 of the Energy Order.

1.15 Subject to the duties already mentioned above, we are required to carry out our respective electricity functions in the manner which we consider is best calculated:

a) To promote the efficient use of electricity and efficiency and economy on the part of persons authorised by licences or exemptions to supply, distribute or participate in the transmission of electricity.

[3] The Energy (Northern Ireland) Order 2003

b) To protect the public from dangers arising from the generation, transmission, distribution or supply of electricity.

c) To secure a diverse, viable and environmentally sustainable long-term energy supply.

d) To promote research into, and the development and use of, new techniques by or on behalf of persons authorised by a licence to generate, supply, distribute or participate in the transmission of electricity.

e) To secure the establishment and maintenance of machinery for promoting the health and safety of persons employed in the generation, transmission, distribution or supply of electricity.

f) To have regard to the effect on the environment of activities connected with the generation, transmission distribution or supply of electricity when carrying out those functions.

1.16 In performing the above duties, we must have regard to the interests of groups of vulnerable consumers in Northern Ireland, comprising the disabled and chronically sick, pensioners, low-income consumers and residents of rural areas.

1.17 In carrying out our electricity functions, we must not discriminate between persons whose activities include generating, supplying, or transmitting electricity.

The electricity sector in Northern Ireland

1.18 Electricity supply companies operate at the commercial interface between the electricity industry and consumers. They:

a) purchase energy from the wholesale market (the all-island Single Electricity Market (SEM)) and incur other wholesale market costs including market operating costs, imperfections charges and generation capacity charges;

b) incur network charges and system service charges which cover the regulated costs of the distribution and transmission network owners and operators, NIE Networks and SONI; and

c) incur their own costs of operating their supply business and capital investment and the cost of financing their activities.

1.19 Supply companies aim to recover their cost, including financing costs / profit from consumers in order to remain viable.

1.20 At the time of writing there were seven supply companies[4] serving domestic consumers in Northern Ireland. The number and percentage of domestic consumers served by each company are shown in Table 1.1 below.

Supply company	Connections ('000)	Connections (%)
Power NI	517	60.9%
SSE Airtricity	148	17.4%
Budget Energy	110	13.0%
Electric Ireland	33	3.9%
Click Energy	36	4.2%
Share Energy	3	<1%
Go Power	1	<1%
Totals	849	100%

Table 1.1: Electricity supply companies by domestic connections

1.21 Only Power NI's domestic supply tariffs are regulated. All commercial electricity supply and all other domestic supply services operate on a commercial and competitive basis.

1.22 The structure of the Power NI Price Control allows the company to recover most of its costs on an actual cost basis, i.e. to pass through these costs to consumers in their bills. These include wholesale market costs including energy costs; Northern Ireland Renewable Obligation (NIRO) costs; Use of System (network) costs and other system costs such as system support service (SSS) costs and public service obligation (PSO) costs. Only the supplier charge, comprising Power NI's internal costs and the margin required to finance its activities, is determined through this Price Control. In the latest assessment of Power NI's tariff, the supplier charge makes up 8.4% of the total revenue Power NI expects to recover, equivalent to £83 of the annual average domestic bill.

Our approach to the SPC25 Price Control

1.23 We consulted on our Approach to the Power NI SPC25 Price Control in November 2023. Having considered the responses to the consultation, we published our approach to the price control in March 2024[5]. The key conclusions underpinning our approach were:

[4] Q4 2024 QREMM
[5] Final approach to the Power NI Supply Price Control 2025 published | Utility Regulator

a) We would continue to set a price control for Power NI's domestic tariff given its continuing dominant position in the domestic supply market.

b) The duration of the price control would be increased to four years with a view to reducing the regulatory burden of carrying out short duration price controls and provide a period of stability while further consideration is given to initiatives such as smart metering and the implementation of alternative tariff structures which will be part of the delivery of net-zero.

c) The broad structure and form of the price control would be maintained including a determination of Power NI's own costs and margin and recovery of other energy costs, market costs and network costs on the basis of actual costs incurred.

d) We would continue to make provision for certain categories of costs defined in the licence to be passed through to consumers. This would include the addition of a category to cover the implementation of smart metering once the impact it will have on electricity suppliers' reasonable costs is known.

e) The determination of Opex would be made for combined domestic and commercial businesses with provision for a method of allocation to distribute determined costs between the domestic and commercial businesses. We proposed introducing a cost sharing mechanism when the actual operating costs incurred are higher or lower than those we determined.

f) We would continue to use CPIH as the general measure of inflation applied during the price control to covert allowances determined in October 2023 prices to nominal values for the relevant regulatory year.

1.24 We received a business plan submission from Power NI comprising a presentation and detailed submission on costings which set out the company's assessment of its business costs and financing costs (margin) for the SPC25 Price Control period. The company's submission was supported by separate consultant's reports on the efficiency of the business and the assessment of financing costs.

1.25 Having reviewed the submissions, we published the draft determination on 19 December 2024 setting out our proposals for the design of the SPC25 Price Control and the determined values of business costs and financing costs (margin) for the price control period. The draft determination was published as a consultation which remained open until Monday 3 March 2025.

1.26 We received two responses to the consultation from:

- Power NI
- Consumer Council for Northern Ireland (CCNI)

We have published these responses in Annex C and D on our website along with the final determination.

1.27 Having given careful consideration to the responses to the draft determination and subsequent information provided by Power NI, we are now publishing our final determination for the SPC25 period. At the same time, we have published a consultation on related licence modifications. The licence modification consultation will close on 23 May 2025.

1.28 Following due consideration of the responses received to the licence modification consultation, we expect to publish our decision on the licence modifications for SPC25 by end of June 2025.

1.29 The date on which the licence modifications take place will be at least 56 days after the publication of the licence modification decision, in line with the requirements of Article 14(10) of the Electricity Order. This period provides an opportunity for Power NI, any other licence holder materially affected by the decision, a qualifying body or association representing one or more of those licence holders, and/or CCNI to appeal the decision on the licence modifications to the Competition and Markets Authority (CMA).

Structure and purpose of this document

1.30 This document is structured in chapters as follows, each addressing different aspects of the price control:

Chapter 2	Scope and Coverage: provides detail on the scope and coverage of this price control.
Chapter 3	Design of the Price Control: considers the design of the price control, focusing on changes to the current arrangements.
Chapter 4	Operating Expenditure (Opex) and Other Costs: sets out a summary of our assessment of the allocation of Power NI's total Opex between price controlled (domestic) and non-price controlled (I&C) customers.
Chapter 5	Margin Review: sets out the proposed allowed margin necessary to finance the price-controlled part of the Power NI business.

Chapter 6	Next Steps: sets out the rest of the timetable for this price control including the consultation on licence modifications.

2. Scope and Coverage

2.1 Power NI's supply licence includes a Supply Charge Restriction Condition (Condition 55, Annex 2) which determines the maximum average charge per unit supplied in respect of "regulated premises"[6].

2.2 "Regulated premises" are defined in the licence as: any premises supplied by the Licensee, other than the following: (a) Non-Domestic Premises and (b) other premises as may be agreed by the Authority and the Licensee from time to time. In effect, these are the domestic premises supplied with electricity by the company.

2.3 Historically, tariffs charged by Power NI has been regulated because the company had a dominant position in electricity supply in Northern Ireland. Following consultation on the approach to the SPC25 Price Control, we concluded that Power NI continues to have a dominant position in the supply of electricity to domestic consumers. Therefore, we have decided that it is in the interest of consumers to continue to regulate the maximum average charge per unit supplied in respect of "regulated premises".

2.4 Initially, all domestic tariffs and some industrial and commercial (I&C) tariffs up to 50MWh per annum were regulated. Further deregulation took place during the 2017 Price Control which removed price regulation from the 0-50MWh I&C market, leaving only domestic customers within the scope of the price control.

2.5 When UR removed I&C tariffs from the scope of the regulated price control in 2017, the combined market share of Power NI/ Energia[7] in the 0-50 MWh sector of the market was 53% by consumption[8]. Data published in our most recent Quarterly Retail Energy Market Monitoring Report Q4 2024[9] shows that for Power NI the equivalent market share by consumption is 44.8%. When we consulted on our "Approach to the 2017 Power NI Supply Price Control", the company's share of the domestic market was 66% by customer number and 64% by consumption. In the Decision paper for the 2014-2017 Price Control, UR had set a market share level of 50% as the threshold for consulting on the possible removal of a control on Power NI tariffs.

2.6 There are currently seven companies supplying electricity to domestic consumers in Northern Ireland. Figure 2.1 below shows the domestic electricity market share by supplier at Quarter 4 (October to December)

[6] The Northern Ireland Authority for Utility Regulation (uregni.gov.uk)
[7] Power NI is part of the Energia Group.
[8] Approach Consultation (uregni.gov.uk)
[9] Q4 2024 QREMM

2024[10]. Power NI remains dominant in the domestic consumer market with a market share of 60.9% by customer number and 60.8% by consumption. Power NI continues to supply more than three times the number of domestic consumers as its nearest competitor, SSE Airtricity (17.4% of customers).

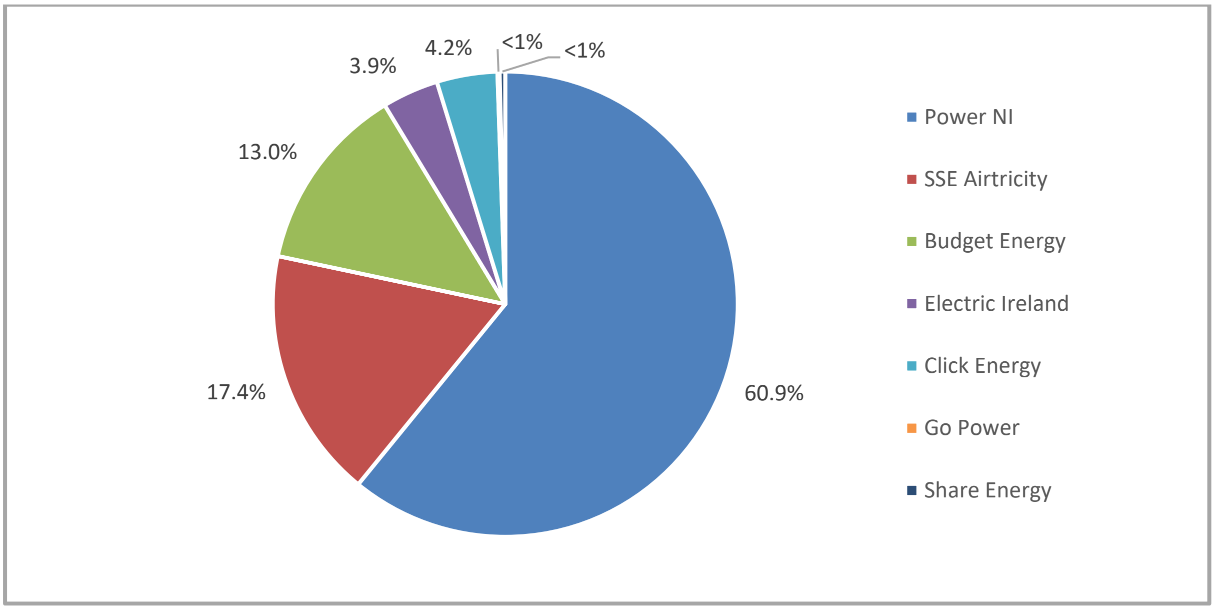

Figure 2.1: Domestic electricity market share (by connections)

2.7 In May 2024, Electric Ireland announced that it was exiting the Northern Ireland domestic market. At that time Electric Ireland had 7.1% of the NI domestic market and this has declined to 4% as it facilitates its domestic customers to transition to other suppliers. A further change in the market saw Share Energy entering the market in September 2024 as a new supplier.

2.8 Within the forthcoming price control period, Power NI has provided a forecast for its customer numbers, as shown in Figure 2.2. It assumed a 4% year-on-year increase from FY25 to FY29 which represents a cumulative 20% increase to the end of the price control. This would increase Power NI's market share from 60% to circa 70% of NI domestic electricity customers.

[10] Q4 2024 QREMM

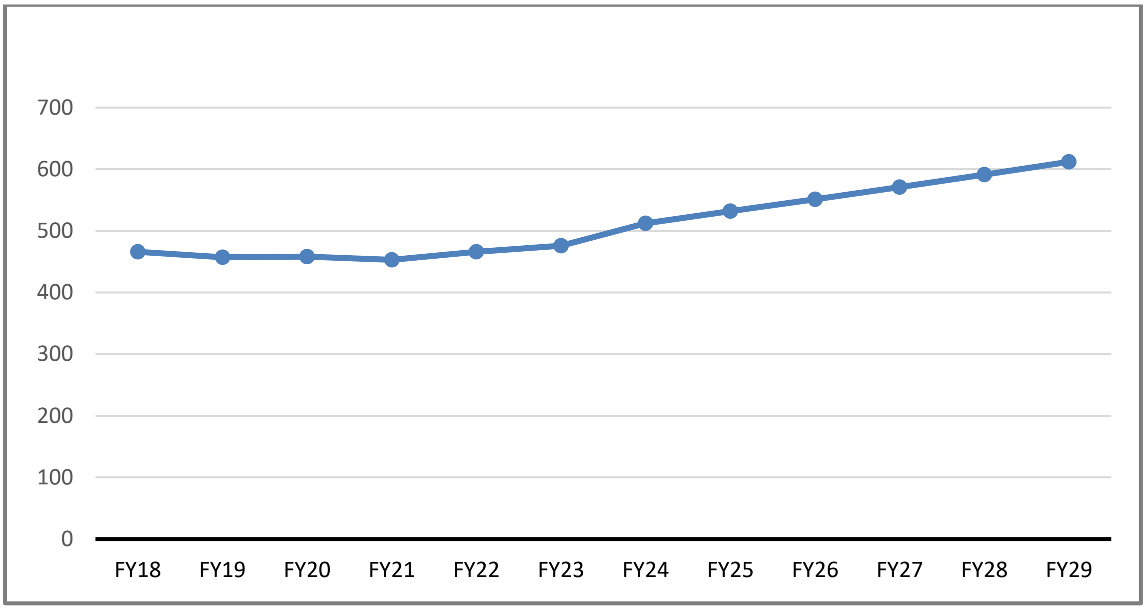

Figure 2.2: Power NI residential customer numbers ('000)

2.9 These forecast figures indicated that the company expects its market share to deepen and become more consolidated during the period of SPC25 and hence there is no reason to think it will be anything other than at least as dominant (if not more so) over the period.

2.10 By comparison, Power NI forecast an 8% year on year increase in sales volumes for residential customers over the duration of the price control as shown in Figure 2.3 below. Power NI's assumption of increased sales volumes (GWh) is based on its premise that consumption will increase due to increased electrification of transport and heat as per the Ten-Year SONI Generation Capacity Statement 2023–2032.

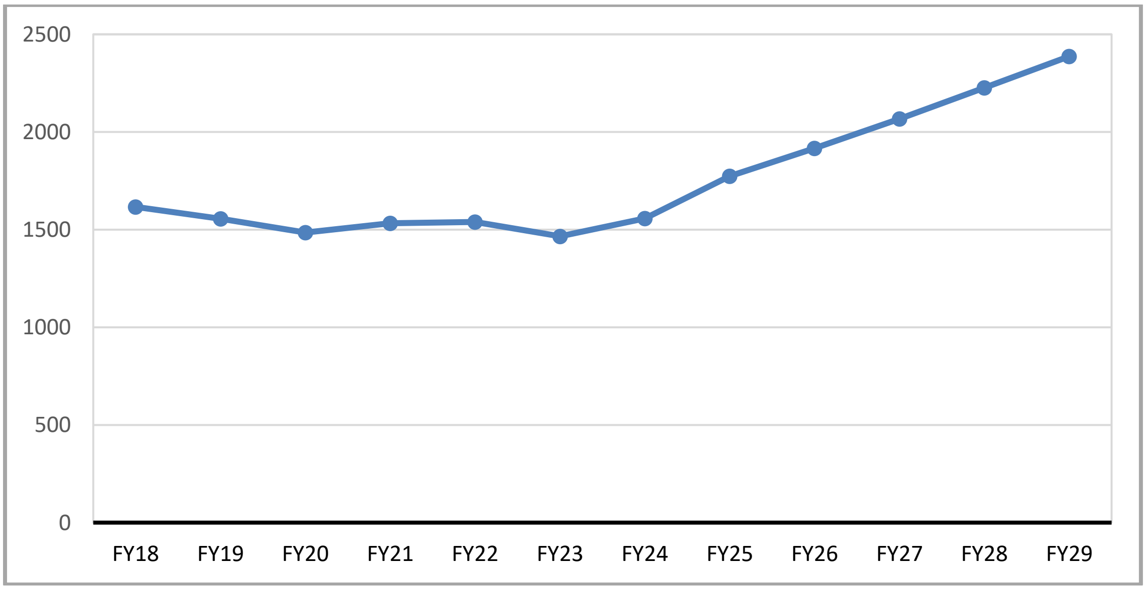

Figure 2.3: Power NI Actual and Forecast Sales Volumes (GWh)

2.11 While Power NI's continued market share alone might be sufficient to show market dominance we also undertook a market concentration analysis using the Herfindahl-Hirschman Index (HHI). In the draft determination, we calculated the HHI for Q3 of 2021 to 2024. We have updated this analysis for this final determination for Q4 of 2021 to 2024 The result of this analysis is shown in Table 2.1 below.

	HHI Index
Q4 2021	3,748
Q4 2022	3,863
Q4 2023	4,075
Q4 2024	4,211

Table 2.1: Herfindahl-Hirschman Index (HHI) for domestic supply market 2021-2024

2.12 Market concentration analysis using the Herfindahl-Hirschman Index (HHI) shows that, since 2021, despite the cost-of-living crisis, the Northern Ireland domestic electricity supply market has become more concentrated. At Q4 2024, the domestic supply market HHI stands at 4,211. An HHI below 1500 is considered to represent a competitive market and an HHI above 2,500 suggests a highly concentrated market. The data presented in Table 2.1 indicates that Power NI continues to hold a dominant position in the domestic electricity supply market.

2.13 In its response to the draft determination, Power NI stated that:

"Power NI market share has reduced from 75% in 2013 to 60% now and the HHI index suggests greater competitive threats exist today."

"Between 2013 and 2023 the levels of concentration fell from a 6057 HHI in 2013 to c. 4077 HHI in 2023. Both the changes in Power NI's market share and the fall in HHI indicates that Power NI is facing greater competition now as opposed to 2013 when the supplier margin was last assessed." [Power NI, Page 28]

2.14 The data in Table 2.1 shows that this downward trend has reversed. In its business plan submission, Power NI indicated that it expected to grow its customer numbers at a rate which would increase market share. Using Power NI's projections and assuming that the number of suppliers in the market stays constant then the HHI is likely to increase to well above 5,000 by 2029.

2.15 In their responses to the draft determination, neither CCNI, nor Power NI objected to the continued regulation of Power NI's tariffs for domestic supply.

2.16 In view of the dominant position Power NI continues to hold in the domestic market, we have decided that it remains in the interest of consumers to continue to regulate the maximum average charge per unit supplied in respect of "regulated premises". We will review the position at the time of setting SPC29.

3. Design of the Price Control

Introduction

3.1 The structure and form of Power NI's supply price control is defined in its supply licence. The financial mechanisms which determine Power NI's regulated tariffs and the revenue it recovers through those tariffs are set out in Condition 55, Annex 2 of the licence.

3.2 In this chapter of our final determination, we considered the design of the next price control covering:

a) Duration of the price control

b) Adjusting for inflation

c) Maximum allowed unit price of electricity (**MS_t**)

d) Modification of the **G_t** term

e) Modification of the **S_t** term

f) Modification of the **E_t** term

3.3 A key part of our determination is the modification of the St term which makes provision for the recovery of Power NI's operating costs, certain other costs and margin. These modifications include changes to the determined parameters underpinning the equation for St, modifications on how the St term is varied for customer numbers and margin and a cost sharing mechanism where actual costs are more than or less than the determined costs.

3.4 In parallel with this final determination, we have published a consultation on proposed licence modifications which give effect to our determination, including the changes to the design of the price control outlined in this chapter.

Duration of the price control

3.5 Recent Power NI Price Controls including extensions have covered three-year and two-year periods (2014-2017, 2017-2019, 2019-2021, 2021-2023 and 2023-2025). Prior to that, the duration of Power NI price controls varied from a one-year to a five-year control. We have determined that the duration of this price control will be four years, 1 April 2025-31 March 2029.

3.6 The duration of a price control is a matter of judgement:

a) If the duration is too short, the incentive for the regulated company to deliver efficiencies is muted and the regulatory burden on both the regulated company and regulator is increased.

b) If the duration is too long, the risk of forecasting errors for both costs and, in the case of a competitive retail market, consumer market share is increased. In addition, it is more likely that a longer duration price control could be affected by extreme events such as the recent volatility in commodity prices and inflation before tariffs are reset.

3.7 In our consultation on the approach to this price control we noted that there is merit in extending the duration of the price control to reduce the regulatory burden of carrying out short duration controls. We proposed extending the Power NI SPC25 Price Control to four years. Extending the duration of the price control will also provide a period of stability while further consideration is given to initiatives such as smart metering and the design and implementation of alternative tariff structures which are likely to be part of the delivery of net-zero.

3.8 We are aware that increasing the duration of this price control to four years increases the risk of cost forecasting errors and/or has the potential to be affected by unforeseen or uncontrollable events. However, four years is not an unusual period for a price control, and many price controls are set for a longer period. In addition to forecast and unknowable risks it is also appropriate to encourage efficiency across the period of the price control. Power NI is continuing to enhance and promote its customer self-service options and is increasing its digitisation of services. This will allow it to make certain efficiencies while at the same time ensuring consumer protection standards are met, particularly with vulnerable customers or those requiring additional and more personal assistance. Taking this into consideration we have evaluated the appropriateness and necessity of a cost sharing mechanism and intend to introduce a mechanism which will be applicable annually to the Opex to both protect against unknowns and incentivise efficiency.

Responses to draft determination on the duration of the price control

3.9 Consumer Council for Northern Ireland (CCNI) support the four-year duration given the risk mitigation measures being introduced particularly regarding forecasting errors and encouraging Power NI to maximise efficiency. CCNI believe that this stability of a four-year control will be positive for consumers and that the cost sharing mechanism has the potential to provide savings for the consumer as well as protecting the company as it recognises the potentiality of future market shocks.

3.10 Power NI stated that it would not characterise a four-year control as being a long control period as it is only one year longer than the 'norm' of a three-year control. Conversely a seven-year control would be a significant change, moving from three to four is not. Power NI also stated that UR appear to use the duration to justify the inclusion of a value sharing mechanism and argue that this is a fundamental design change to how Opex is dealt with within the current and all previous price controls.

UR's response to the consultation comments on the duration of the price control

3.11 Neither CCNI nor Power NI raised any objection to a four-year duration to the current price control. Power NI noted that we used the extended price control period to support the introduction of a cost sharing mechanism, an issue which we have addressed below, beginning at Paragraph 3.43.

3.12 Taking account of the responses received and the comments above, our final determination maintains a four-year duration for the price control.

Adjusting for inflation

3.13 In the current licence, key monetary values used to determine the maximum allowed unit price for electricity are stated in October 2023 prices. The Consumer Prices Index including owner occupiers' housing costs (CPIH) was applied as a general measure of inflation to convert these values to nominal values when calculating tariffs. The CPIH index for October is used as the representative value for the relevant regulatory year.

3.14 For SPC25, we stated the key monetary licence values which will be used to determine the maximum allowed unit price for electricity in October 2023 prices. We will continue to use CPIH as the general measure of inflation to convert these values to nominal values when calculating tariffs. The CPIH index for October will continue to be applied as the representative value for the relevant regulatory year.

Responses to draft determination on adjusting for inflation

3.15 We did not receive any response to our proposal to maintain CPIH as the general measure of inflation applied in the price control. Our final determination therefore maintains this approach.

Maximum allowed unit price of electricity (MS_t)

3.16 The structure and form of Power NI's supply price control is defined in its supply licence. The financial mechanisms which determine Power NI's regulated tariffs and the revenue it recovers through those tariffs are set out in Condition 55, Annex 2 of the licence. At present, Power NI's maximum allowed unit price of electricity (**MS_t**) for domestic customers is calculated using the formula for **MS_t** below.

$MS_t = G_t + U_t + S_t + KS_t + J_t + E_t – D_t$

in any given year ‘t’.

3.17 We do not propose changing the following terms of the **MS_t** equation:

- The **U_t term** covering transmission and distribution network costs.
- The **KS_t term** covering revenue under or over-recovery in the previous year which can be collected by the business (under-recovery) or given back to consumers (over-recovery).
- The **J_t term** covering the cost of the buy-out from the Northern Ireland Renewables Obligation (NIRO).
- The **D_t term** covering the sharing of any savings of costs between the Licensee and consumers in respect of costs of meeting renewables obligations and other costs specified by UR from time to time.

3.18 These terms allow Power NI to recover a range of networks costs and energy subsidy costs on the basis of actual cost incurred. A full definition of these terms can be found in the current Power NI Licence[11].

3.19 The focus of this final determination in respect of the maximum allowed unit price for electricity is the modification of the **G_t**, **S_t** and **E_t** terms of the **MS_t** equation.

3.20 The **G_t** term determines the energy and associated costs which Power NI can recover through its tariffs. We propose to modify the licence to clarify and make explicit the mechanism, already used during the previous price control period, whereby the company can recover the cost of collateral required to engage in the energy markets.

3.21 The **S_t** term determines the operating costs, other costs and margin which Power NI can recover through its tariff. Following the proposal in the draft determination we now intend to modify the **S_t** term of the licence as set out in the section below beginning at Paragraph 3.26.

3.22 The operating costs and other costs recovered through the **S_t** term excludes certain pass-through costs which are recovered through **E_t** term. Information on the costs recovered through the Et term are described in the section

[11] The Northern Ireland Authority for Utility Regulation

below, beginning at Paragraph 3.72. This reproduces the definition of the various Et terms in the existing licence, describes whether these terms will be retained, amended or deleted and identifies new terms covering additional categories of pass-through costs.

Modification of the G_t term

3.23 During the last price control period, an amount was deducted from the determined margin which represented the actual cost of credit facilities required to provide collateral necessary to purchase energy and other products required to provide energy to domestic consumers. When tariffs are determined, this deduction is replaced by the actual cost of this type of credit, first as a forecast and then as actual costs once historical values when they become available. This has been done through the mechanism of the $\mathbf{G_t}$ term. We intend to continue this practice in SPC25. However, through the consultation process following issue of the draft determination we have come to recognise that both the $\mathbf{G_t}$ term itself and the methodology for making these adjustments could be both clearer and more explicit.

3.24 For the SPC25 Price Control, we therefore propose to modify the $\mathbf{G_t}$ term to clarify and make explicit the mechanism by which this amount can be recovered. We propose to do this by modifying the definition of the $\mathbf{G_t}$ term which defines the amount which can be recovered under the mechanism in accordance with the principles set out in a methodology entitled "Power NI Supply Price Control G_t Cost of Credit Mechanism" published to be published in final form around the time that we determine the licence modifications.

3.25 A draft of that methodology is set out in Chapter 5, beginning at Paragraph 5.80. We are consulting on this draft methodology with Power NI, and other interested parties generally as an associated part of the consultation on licence modifications under Article 14 of the Energy Order. We emphasise that its purpose is to codify and therefore ensure the transparency of the historical approach to costs recoverable under the $\mathbf{G_t}$ term, rather than to introduce anything substantively new.

Modification of the S_t term

3.26 The $\mathbf{S_t}$ term of the licence determines the operating expenditure (Opex), other costs and margin which Power NI can recover through its tariff.

3.27 Detailed information on the final determination of operating cost and other cost allowances which will underpin the St term can be found in Chapter 4. Detailed information on our assessment of the margin which Power NI should be able to recover to finance its business can be found in Chapter 5.

3.28 The key monetary values in this section are in October 2023 prices. As noted above, CPIH will be applied as a general measure of inflation to determine the maximum allowed unit price for electricity in nominal terms.

The current St term

3.29 The $\mathbf{S_t}$ term is currently defined in the licence as the allowed charge in pence per unit supplied to supply customers at regulated premises in relevant year t, which is derived from the following formula

$$S_t = \left((Pf\ + (Pc * C_t) - A_t) * Pl_t\right)/QS_t$$

Where:

Pf	is a fixed sum determined in the price control.
Pc	is a fixed amount per customer determined in the price control.
C_t	is the number of supply customers.

The terms above define the determined costs for the Power NI residential and commercial businesses. These combined business costs are then modified by the terms:

A_t	which is a sum determined from a methodology defined in the licence, or such other methodology as approved by UR, to reflect the operating costs attributable to the Power NI commercial business and other costs not related to the Northern Ireland domestic consumers (see the section below beginning at paragraph 3.61).
Pl_t	is the application of CPIH to inflate costs determined in base year prices to nominal terms for the relevant regulatory year.
QS_t	is the quantity supplied in the relevant year.

3.30 As a result, the $\mathbf{S_t}$ term has been part fixed and part variable relative to customer numbers. In broad terms circa 70% of the St term was fixed and 30% variable in terms of customer numbers. This split was broadly in line with the historical proportions of Opex and margin.

Modifications to the St term

3.31 We intend to modify the St term of the licence so that it is derived from the following equation:

$S_t = (100*(((Pf - A_t)+(Pv * MF_t)) * Pl_t) - CS_t) / QS_t$

3.32 For the final determination, we have corrected this equation from that published in the draft determination to properly divide all elements of the equation, including the **CS_t** term, by the quantity supplied in the relevant year (**QS_t**)

3.33 We intend to:

a) Align the fixed amount (**P_f**) with the determined operational cost and other costs as shown in Table 4.2. These costs remain relatively constant over the four years of the price control and show no significant variation with customer numbers. Therefore, we intend to use the average of the determined values which will apply in each of the four years of the price control.

b) Restructure the equation to group the **P_f** and **A_t** terms together. While this has no impact on the functioning of the equation, it serves to confirm that the **A_t** term is an adjustment to the operational cost allowances of the price control.

c) Amend the variable element of the **S_t** term such that **P_v** is the determined value of the margin subject to the application of a Margin Factor (**MF_t**) to reflect changes in the number of customers and the market price of energy relative to that which underpins our determination of margin. The calculation of the Margin Factor is set out in Chapter 5, beginning at Paragraph 5.104.

d) Introduce the deduction of a cost sharing amount (**CS_t**) to reflect a share of any cost saving against the determined S_t amount which is returned to customers.

e) Include an additional factor of 100 to align with the definition of the St term as a value in pence per unit.

3.34 Our determined values for the terms of the St equation are set out below. Monetary values are stated in October 2023 prices.

Pf — £41,138,951 per annum, being the average value of the determined operating and other costs as set out in Table 4.2. This includes an allowance for certain lines of depreciation and costs which will be recharged or recovered by Power NI when it uses its systems in other areas of its work. When tariffs are determined, this amount is subject to a deduction for commercial and other use through the A_t term described below, which has historically run at between 22 and 24% of this determined amount.

Pv	£15.3m/a, being the average value of the margin determined in Chapter 5 in October 2023 prices.
PI_t	is the application of CPIH to inflate costs determined in base year prices to nominal terms for the relevant regulatory year.
QS_t	is the quantity supplied in the relevant year.
CS_t	is a cost sharing amount as defined immediately below.

Responses to draft determination on modifications to the St term

3.35 CCNI did not respond on the revised equation proposed for the **St** term. It broadly supported the proposal to allow the margin to vary with both customer numbers and the market price of power.

3.36 Power NI's response challenged the proposal to include a mechanism whereby margin would vary in line with the market price of energy. It made the point that this only protects Power NI on the basis that the base margin is reasonable in the first instance. Power NI states that UR has failed to consider the increased risks faced by the business, and that the business/ group needs to effectively ringfence for potential market shocks, regardless of whether or not they materialise. Simply put, in the submission of Power NI, the business cannot be funded on a retrospective basis - it must have sufficient facilities available that covers high side forecasts and shocks.

3.37 Power NI also noted that UR's methodology does not recognise that the capital requirements of the business are not linear and that certain costs will increase as market price falls, e.g. hedging collateral. Power NI argued that the methodology proposed must contain a floor mechanism (as evident in GB) to recognise the capitalisation of those items which either do not have a linear relationship or are required regardless of market energy price.

UR's response to the consultation comments on the St term

3.38 We agree with the company that the proposed mechanism only protects the company on the basis that the base margin is reasonable in the first instance. However, we disagree with the company on the basis for determining a reasonable margin and our view is that the base margin figure as determined in Chapter 5 is entirely reasonable for the reasons set out in this chapter.

3.39 The company's response highlights a challenge of reaching a determination of margin which has sufficient flexibility available to cover high side forecasts and shocks. In its business plan submission, the company's proposed approach to this was to set a margin on the basis of a market price for energy of £150/MWh. Its rationale was that the market price for energy had exceeded this frequently in the recent past when prices had been affected by external market shocks. However, it is clear that the market price for energy has not exceeded £150/MWh in the last two years and future energy prices in GB markets up to two years ahead remain well below £150/MWh. Since the market price for energy was a key driver in the company's forecasts of capital requirement, which we have largely adopted in this determination, it seems reasonable to have a mechanism which adjusts margin to reflect the actual market price of energy.

3.40 The proposed mechanism has a forward-looking element, the hedged price of energy, which might be something a rational investor would consider as they finance an electricity supply company on a forward basis, and then a correction mechanism if the price of energy in the Day Ahead Market (DAM) is higher than this. Considering the price control in the round, it is also important to recognise that other mechanisms are available to deal with price shocks:

a) A mark up of circa 35% on our calculated level of margin to address the peak to average capital requirement over the year (which might or might not occur at the same time as a price increase) and other cost shocks generally.

b) The asset beta in the calculation of the cost of equity which rewards the company for risk.

c) The opportunity that not all the determined margin will be deployed if the DAM prices fall below the forward hedged price.

d) The opportunity to reset tariffs when the forward price of energy has increased, which will factor an increased allowance for margin into prices.

e) The cost of credit recovery mechanism which will allow the company to recover some of its costs of increasing collateral and changes in the types of collateral required.

3.41 In view of the inherent uncertainty in future power prices, and the range of other parts of the price control which make provision for cost shocks, we continue to consider that the approach previously set out in the draft determination provides a reasonable and appropriate balance of risk and reward.

3.42 In respect of company's proposal that there should be a floor on the margin, we recognise that there is some merit in this, notwithstanding the fact that the company did not quantify what floor it considered appropriate or quantify the effect of increasing hedging collateral as market prices fall. We recognise that the strength of our proposed mechanism, which provides significant protection as energy prices increase, would result in a very low level of margin if energy prices fall. Therefore, we have added a floor price of energy of £90/MWh in October 2023 prices, which will be applied when the $\mathbf{MF_t}$ factor is calculated. This is consistent with the current level of margin of £12.0m in 2023/24, given the number of customers in that year.

Cost sharing amount

3.43 When we set out our approach to the price control, we noted that increasing the duration of the price control to four years increases the risk of cost forecasting errors. We suggested that one way of mitigating this risk was to introduce a cost sharing mechanisms as part of the overall design of the price control.

3.44 In response to our Approach consultation on this issue:

a) CCNI commented that it would expect to see appropriate mechanisms in the draft determination to help minimise the risk of forecasting errors and ensure Power NI is encouraged to maximise its efficiency across the period.

b) Power NI noted that cost sharing could be an important risk mitigation factor but said that it would need to understand the mechanics of how such a mechanism would be implemented.

3.45 There is strong regulatory precedent for the use of cost sharing mechanisms to mitigate the risk of forecasting errors over the duration of a price control. They are widely used across price controls of many types. For example:

a) Our regulation of NIE Networks includes a 50:50 cost sharing mechanism on both capital investment and operating costs.

b) Our regulation of the transmission system operator SONI includes a 25:75 cost sharing mechanism on costs subject to fixed determined allowances.

c) Our regulation of the gas distribution companies includes a cost 35:65 cost risk sharing mechanism on Capex investment only.

d) Our regulation of the Gas to the West project included a 35:65 cost sharing mechanism on capital investment.

e) Ofwat and Ofgem also include cost sharing mechanisms in their regulation of the water and energy sectors in GB.

3.46 In view of the risk which can be mitigated by a cost sharing mechanism and the body of regulatory precedent strongly supporting the use of such a mechanism, we have concluded that it is appropriate to introduce a cost sharing mechanism into the SPC25 Price Control.

3.47 The strength of a cost sharing mechanism is a matter of judgement which must balance the relative financial risk to the regulated company and the effectiveness of the mechanism incentivising the company to reveal lower costs. In determining the cost sharing rate for Power NI, we have:

a) Taken account of the cost sharing rates outlined above which range from 50:50 to 25:75, with the company retaining the first part and the second part returned to consumers.

b) That the larger the company, in terms of RAB and portfolio of activities, and therefore its ability to mitigate or absorb cost shocks, the larger the cost share typically attributed to the company.

3.48 In light of this experience and precedent, we concluded in the draft determination that an appropriate strength for a cost sharing mechanism in SPC25 would be a 35:65 symmetrical cost share in favour of the customer. For the avoidance of doubt, 65% of any savings would be passed back to the customer through the tariff and Power NI would retain 35% of any saving. Equally, in the event of an overspend, Power NI will bear 35% of any additional spending and the customer will bear the remaining 65% of the additional cost through the domestic tariff. We have no new evidence from the consultation to change our decision.

3.49 To give proper effect to the $\mathbf{CS_t}$ term in the equation for **St** at Paragraph 3.31, it is necessary to:

a) Calculate the **CSt** in nominal terms.

b) Calculate the adjustment as a positive value where there is a saving in actual cost relative to the allowance.

c) Adjust the saving to take account of the fact that the determined $\mathbf{P_f}$ value and the reported actual costs are for the company's residential and commercial business combined. In the formula for **St** above includes a deduction from the $\mathbf{P_f}$ allowance in respect of commercial business costs. A similar approach must be applied to the actual costs of the combined business.

3.50 These objectives can be met through the application of the following equation for the $\mathbf{CS_t}$ term:

$$CS_t = 65\% * \left(\left(P_f * Pl_t + E_t\right) - AO_t\right) * \left(1 - \frac{A_t}{\left(P_f + E_t/Pl_t\right)}\right)$$

Where:

AO_t is the actual operational cost and other costs in nominal terms incurred by the company which fall within the categories of costs set out in Table 4.2 and the categories of costs which fall into the Et term to the extent that they are not recovered under any other part of the licence or any other licence.

And the terms **P_f**, **Pl_t**, **E_t** and **A_t** have the meanings ascribed to them above.

Responses to draft determination in respect of cost sharing

3.51 CCNI highlighted that it would like to see an appropriate mechanism to minimise risk of forecasting errors and maximise efficiency. Furthermore, it was of the view that the cost share is consistent with other Northern Ireland regulated organisations and provides potential savings for customers while recognising potential market shocks. Therefore, CCNI support the introduction of the cost sharing mechanism.

3.52 Power NI in its response to the draft determination disagreed with the introduction of a cost sharing mechanism. The company made a number of submissions regarding the mechanism. These were:

- **Incentive based regulation**. The cost sharing mechanism removes performance incentivisation. The company is of the view that the existing price control structure incentivises efficiency by allowing the company to retain the benefits until the end of the price control when it is then rebased. It suggested that this is a standard regulatory approach used to create incentives.

- **Application to all line items.** Power NI suggested there was a flaw in UR's intention to introduce the cost sharing mechanism to all line items. Power NI, in the first instance, argued that this is inappropriate and secondly it noted that elements of similar applications of sharing mechanisms for NIE Networks and SONI have identified this and do not apply the mechanism. In the opinion of the company, bad debt should not be included in the cost sharing mechanism as it is heavily linked not only energy to and non-energy prices but also customer consumption and ability to pay.

- **Increase regulatory burden**. The company suggested that the mechanism will result in additional regulatory burden. Specifically, it argued that this will involve an annual line by line scrutiny of actual costs versus price control allowance levels.

- **Consumer Risk**. Power NI also suggested that the cost sharing mechanism poses a risk to consumers as it would expose customers to cost increases recoverable through the duration of the control period and at the same time removes Power NI's efficiency incentive.

UR's response to the consultation comments in respect of cost sharing

3.53 **Incentive based regulation**. We do not agree that a cost sharing mechanism reduces or is somehow incompatible with incentive-based regulation. Cost sharing is a commonly used tool in regulation deployed both by UR and other regulators as described above. It mitigates the risk of forecasting errors over the duration of a price control and addresses the issue of asymmetry of information. It also reduces the risk to companies from increased costs, mitigating the impact of cost shocks on financeability. We are satisfied that the ability of Power NI to retain 35% of any efficiency gains provides a sufficiently strong incentive to promote efficiency.

3.54 **Application to all line items.** We do not believe that our determination to apply a cost sharing mechanism to all costs is flawed. Including all costs in a cost sharing mechanism avoids potential for allocation between cost categories included in the mechanism and those not included in the mechanism which risks undermining the process.

3.55 Specific exclusions can be applied and the case of NIE Networks is a useful example where licence fees and business rates are excluded from the cost sharing mechanism because they are driven by specific exogenous processes. A similar mechanism allows Power NI to recover licence fee costs through an Et term and Power NI's rates bill is relatively small compared to its total operating costs.

3.56 The company also cites bad debt as a possible exclusion because it is heavily linked not only to energy and non-energy prices but also customer consumption and ability to pay. However, there is a trade-off between the level of bad debt the company incurs and the effort it expends in managing bad debt. For example, Power NI is about to implement the consumer programme "For Your Benefit". The objective of this programme is to assist vulnerable customers. The programme, among other objectives, will focus on helping "tackle debt issues and promote Power NI's various schemes e.g. keypad and Customer Care Register." The scheme also offers a range of services which all contribute to alleviation of debt. Excluding bad debt cost from the cost sharing mechanism would undermine the economic trade-off the company must make as it endeavours to manage its bad debt cost efficiently. To exclude the cost of managing bad debt would create the risk of allocation error discussed above.

3.57 **Increase regulatory burden.** We disagree that the cost sharing mechanism introduces a significant and ongoing regulatory burden. We have set out a simple mechanistic equation in our proposals above which draws on parameters which already exist, and the actual operational costs and other costs incurred by the company. It does not require the quarterly reporting which was necessary to support the cost pass through mechanisms introduced as part of the last review of the price control. It can be completed as part of the normal year end assessments at the same time as the $\mathbf{A_t}$ and $\mathbf{E_t}$ terms are finalised.

3.58 **Consumer Risk**. We disagree that the cost sharing mechanism introduces an inherent risk to consumers and exposes them to higher prices. Cost sharing mechanisms are an established and accepted regulatory practice within other incentive based regulatory regimes. It maintains a strong incentive for Power NI not to overspend as for every £1 overspend, 35p is paid from the company's own funds. We also note that over the last two years, the company continued to out-perform its PPM allowances which were subject to a 35:65 cost share in favour of the customer, allowing the company to gain £1m and return £2m to consumers.

3.59 In considering consumer risk associated with a cost risk sharing mechanism, we note, as an example, that the company has significantly underspent its estimate of 2024/25 costs included in its business plan submission which formed the basis of its forecast of costs over the SPC25 Price Control. The company has highlighted reasons why this was the case - relating to the delayed implementation of its new customer contact and billing system and a focus on preparing for the sale of its parent company. In our determination of Opex, we have accepted the company's explanation of this apparent underspend and the need for the additional expenditure that the company has proposed for SPC25. However, had 2024/25 been the first year of the price control, and in the absence of a cost sharing mechanism, the company would have made an additional profit of £5m for reasons which were not directly related to sustainable efficient delivery. The application of the cost sharing mechanism would have reduced this benefit to the company to £1.8m. This points to the wider issue of asymmetry of information in the price control process and the difficulty and regulatory burden of distinguishing between cost reduction and efficiency in delivery. A cost sharing mechanism mitigates against these inherent issues while also protecting the company against the full impact of unforeseen and unavoidable increases in cost over the duration of a longer price control.

3.60 Taking account of all the points identified above, we have decided that it is in the interest of consumers to implement the cost risk sharing mechanism set out above.

Allocation of costs between the residential and commercial businesses (the At term)

3.61 The determination of operational costs and other costs (the $\mathbf{P_f}$ term above), covers the costs of Power NI's residential and commercial businesses. To determine the $\mathbf{S_t}$ term for the regulated domestic business, it is necessary to deduct an appropriate amount to reflect the operational and other costs of the commercial business. This deduction is the $\mathbf{A_t}$ term in the equation for $\mathbf{S_t}$ at Paragraph 3.31 above.

3.62 In the licence at present the $\mathbf{A_t}$ term is the sum of two separate components defined as follows:

a) £5.696 million or, such other amount as reasonably determined by the Authority using the same methodology used to arrive at the amount of £5.696 million or such other methodology as approved by the Authority (i.e. UR); plus

b) £6.59 *(R_t – PN_t)

where:

$\mathbf{R_t}$ means the number of persons that are on 30th September in relevant year t registered as a customer on the Licensee's customer billing system, determined in such manner as the Authority shall specify from time to time by notice to the Licensee; and

$\mathbf{PN_t}$ means the number of persons that are on 30th September in relevant year t persons in relation to whom the Licensee is the Registered Supplier (as defined in Condition 27 of the licence), determined in such manner as the authority shall specify from time to time by notice to the Licensee.

3.63 The monetary value in the first part of the definition is an historical figure which has not been used for some time. Instead, an established methodology has been developed based on a detailed activity-based costing methodology using four cost drivers: units sold, revenue, number of customers and bills, or, for some costs, combinations of those main drivers. The drivers are applied to a detailed set of subsets of activity costs within each of the main cost categories for determined operational costs underpinning the **Pf** term.

3.64 To place the $\mathbf{A_t}$ term in context, the most recent allocation of the main drivers between the residential and commercial businesses are summarised in Table 3.1 below. For 2024-25, $\mathbf{A_t}$ was 22% of the **St** value. Between FY19 and FY24, this percentage ranged from 22% to 24%.

	Total at Sep 2024 '000	Unregulated Sep 2024 '000	Unregulated %
Units	2,260	631	27.90%
Revenues	613,338	155,511	25.35%
Avg. Customers	549	34	6.18%
Bills	1,368	150	10.94%

Table 3.1: Main drivers for apportionment of regulated and deregulated costs

3.65 We will continue with this methodology for SPC25 beginning from the established $\mathbf{A_t}$ methodology using in the 2024-25 tariff submission updated to reflect the values of this final determination. We will continue to reserve the option of adopting such other methodology as approved by UR to address changes in circumstances.

3.66 The second part of the $\mathbf{A_t}$ term recognises the possibility that Power NI might wish to use its systems to host consumers for which the company is not the Registered Supplier. We intend to maintain the structure of this part of the $\mathbf{A_t}$ term for SPC25. The company is currently updating its billing systems. Until this work is complete, we will continue to use the value of £6.59 / customer (adjusted for inflation to 2023 prices). The billing system is now live and has entered the hyper-care period. Once this period of embedding the system has concluded and all actual costs are known then the amount to be recharged to other parts of the business will be updated. It is likely that this will happen in June 2025. Once the cost of the new systems is known, we will amend this value to reflect these costs in the final publication of the licence modifications in June 2025.

Responses to draft determination in respect of cost allocation

3.67 CCNI acknowledged that UR had reviewed the existing cost allocation methodology and affirmed our intention to continue to use it by keeping the current cost drivers, subject to ongoing review. It expressed its support for this approach and emphasised the importance of the review process to ensure that electricity tariffs for consumers are based only on those costs relevant to the domestic market.

3.68 Power NI acknowledged that the allocation of Opex to its activities outside the scope of the price control, such as, the deregulated part of the business and the consumers who are hosted on its systems which the company is not the Registered Supplier, has been a long-established process and is well understood by both Power NI and UR. However, Power NI argued that UR's intention to retain the methodology while, at the same time, reserving the option of adopting such other methodology as approved by UR to address changes in circumstances, introduced a level of uncertainty which it says is entirely unreasonable.

UR's response to the consultation comments in cost allocation

3.69 UR agrees that the allocation of the Opex has been long established, and it is not our intention to amend this process at this time. However, we note that the current licence states that the first element of the $\mathbf{A_t}$ term shall be:

"£5.696 million or, such other amount as reasonably determined by the Authority using the same methodology used to arrive at the amount of £5.696 million <u>or such other methodology as approved by the Authority"</u>.

3.70 The licence already allows the methodology used to calculate the $\mathbf{A_t}$ term to be revised should it be deemed necessary. In our view, it is reasonable to maintain that provision to allow for future changes in the scope or the extent of the Power NI business which might impact on the allocation of costs.

3.71 In our proposed licence modifications, we intend to consult on two further changes to the definition of the A_t term:

a) We have increased the sum of 5.696 million in sub-paragraph (a) of the current licence definition to £7.89m (in October 2023 prices) to reflect the value of the A_t term in 2023/24. However, we note that this amount acts as a fallback position which would only be used if UR failed to determine an up-to-date value through the established methodology.

b) We have increased the value of £6.59 in sub-paragraph (b) of the current licence definition to £7.11 (in October 2023 prices) to allow for inflation

Pass through costs (the E_t term)

3.72 The licence formula for the maximum allowed unit price of electricity (MSt) includes the $\mathbf{E_t}$ **term** covering certain categories of costs defined in the licence to be passed through to customers.

3.73 As part of this price control, we assessed the scope of these pass-through cost categories and considered whether they should be retained, amended or deleted for the SPC25 Price Control. We have also considered whether additional categories of pass-through costs should be added for the SPC25 Price Control. Our determination for SPC25 is set out in Table 3.2 below.

Ref	Existing Et term	Proposed revision for SPC25
1	(a) any reasonable costs incurred by the Supply Business in complying with the requirements imposed on the Licensee under legislation and other legal requirements through which Directive 2009/72/EC is implemented, whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or any other licence.	Retain
2	(b) any reasonable costs incurred by the Supply Business in complying with the requirements imposed on the Licensee under the arrangements for the Single Electricity Market (being the project described in the Memorandum of Understanding dated 23 August 2004 and made between the Authority and the Commission for Energy Regulation in Dublin), whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Retain
3	(c) any payments made to NIE Ltd in relation to costs of systems implemented for compliance with (i) the requirements imposed under legislation and other legal requirements through which Directive 2009/72/EC is implemented; and (ii) the requirements imposed under the arrangements for the Single Electricity Market (being the project described in the Memorandum of Understanding dated 23 August 2004 and made between the Authority and the Commission for Energy Regulation in Dublin); in both cases including annual depreciation and financing costs and whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Retain

Ref	Existing Et term	Proposed revision for SPC25
4	(d) pension deficit costs of: (i) £400,000 per year, or (ii) such other amount, as reasonably determined by the Authority and notified to the Licensee, which amount reflects and is calculated in accordance with: (A) a report submitted by the Licensee to the Authority setting out the results of the most recent triennial actuarial review undertaken by the Licensee, or (B) the regulatory principles, determined by the Authority and notified to the Licensee, as applicable (from the date specified in the Authority's determination) to the allowance of pension deficit costs.	Amend We intend to retain the wording of the term but amend the value of £400,000 to £519,000 to reflect the most recent triennial actuarial review undertaken by the Licensee. Subject to clarification from Power NI, we intend to clarify the term to note the specified amount is a nominal amount. We intend to clarify the term to confirm that the recovery of the amount in tariffs is subject to that amount being applied to the relevant pension fund(s).
5	(e) the amounts apportioned or allocated to the Supply Business in respect of the fees paid by the Licensee under Condition 11	Retain
6	(f) a reasonable rate of return as reasonably determined by the Authority on the capital represented by the costs incurred by the Supply Business associated with Phase III of the Enduring Solutions Project and an allowance for depreciation of the capital represented by such costs	Retain
7	(g) any reasonable costs incurred by the Supply Business associated with the European Target Model Project, whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Retain
8	(h) any reasonable costs incurred by the Supply Business associated with the upgrade of its customer care and billing systems (including software and hardware) implemented as part of the Enduring Solutions Project, whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Retain

Ref	Existing Et term	Proposed revision for SPC25
9	(i) any reasonable costs incurred by the Supply Business in complying with any requirement that: (i) is imposed on the Licensee under a legal instrument through which Directive 2012/27/EU is implemented; and (ii) is substantially equivalent, or otherwise corresponds, to any requirement imposed under the Electricity and Gas (Energy Companies Obligation) Order 2012 on any person holding an electricity supply licence granted (or treated as granted) under section 6(1)(d) of the Electricity Act 1989, whether before or after the coming into effect of this Annex, as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Retain
10	any reasonable costs incurred (or to be incurred) by the Licensee to comply with any new or modified Conditions of the licence which are made in consequence of the Authority's project described in the document entitled 'Consumer Protection Programme - Final Decisions'.	Retain
11	k) any reasonable costs associated with IT systems (including support), employment related, and Payment Providers + Mailing costs as reasonably determined by the Authority, and to the extent not recovered under another part of the licence or under any other licence.	Delete This term was introduced in licence modifications which came into effect on 1 April 2023. It provided for increased costs of IT systems (including support), employment related and Payment Providers + Mailing costs over and above those allowed in the historical St term. These increased costs are now incorporated in the proposed amended St term as described above, making this term redundant.
12	(l) such other amount which reflects and is calculated in accordance with a sharing mechanism, specified from time to time by the Authority, to reflect a reasonable sharing of any savings made in respect of "Payment Providers + Mailing" (should this scenario arise) for which a cost allowance within St has been provided.	Delete We intend to introduce a broader cost sharing mechanism which will include Payment Providers + Mailing costs. We intend to incorporate this mechanism as part of the St term as described above, making this term redundant.

Ref	Existing Et term	Proposed revision for SPC25
13	(m) any reasonable costs incurred (or to be incurred) by the Licensee in administering the provision and delivery of EBSS payments and other associated requirements, as set out in the direction made on 22 December 2022 by the Secretary of State pursuant to section 22 of the Energy Prices Act 2022 (the EBSS AFP NI Direction), as reasonably determined by the Authority and to the extent such costs are not recovered or recoverable under another part of this licence, under any other licence or under any other legal instrument (including, for the avoidance of doubt, the EBSS AFP NI Direction).	Delete This term was introduced in licence modifications which came into effect on 1 April 2023. It made provision for the recovery of the costs in administering the provision and delivery of Energy Bill Support Scheme (EBSS) payments and other associated requirements for the Alternative Fuel Payment (AFP). As the term is linked to specific legislation and the provision has already been made for cost recover, we consider the term redundant.
14	New term making provision for future implementation costs of smart metering.	Any reasonable costs incurred (or to be incurred) by the Licensee with regard to smart metering for domestic consumer which is clearly in pursuit of a Ministerial policy decision, as reasonably determined by the Authority and to the extent such costs are not recovered or recoverable under another part of this licence or under any other licence.
15	New term making provision for future costs of the Digital Engine project.	Any reasonable costs incurred (or to be incurred) by the licensee associated with the Digital Engine project, as reasonably determined by the Authority and to the extent such costs are not recovered or recoverable under another part of this licence or under any other licence.

Table 3.2: Proposed amendments to pass through costs (the Et term)

3.74 The additional Et terms included in Table 3.2 are:

a) **Smart metering**. The term makes provision for the company to recover smart metering costs once a clear Ministerial policy decision is in place to underpin such costs. Power NI will be required to bring forward detailed proposals and associated costs for approval by UR. We have excluded these costs from the calculation of margin and an additional return on capital will be recovered at the cost of capital determined in Chapter 5.

b) **Digital Engine costs**. This term makes provision for the company to recover Digital Engine costs. At this stage it is assumed that this project is for the development of apps, systems integrations or digital sustainability as the energy transition progresses. However, Power NI will need to furnish UR with a detailed proposal and associated costs. We have excluded these costs from the calculation of margin and an additional return on capital will be recovered at the cost of capital determined in Chapter 5.

3.75 The company has made provision for the cost of financing a number of Et items when calculating the working capital requirement which underpinned its margin. We have followed the same approach when determining the margin for SPC25, applying a nominal, pre-tax, cost of equity to calculate contribution to the overall margin. Where a nominal cost of equity has been included in the margin, the cost recovered for capital investment under these terms would be limited to nominal depreciation.

Responses to draft determination in respect of additional Et terms

3.76 CCNI was supportive of UR's proposal to include two new Et terms for Smart Metering and Digital Engine. It also reiterated the need for Power NI to provide detailed proposals on the nature and scope of both projects. CCNI stated that these proposals would need to include details of deliverables, associated costs and demonstrations that they are in the interest of domestic consumers.

3.77 CCNI also noted that "there is a wide range of digital awareness across the consumer population and that proposals should recognise the differing needs of consumer classes and ensure that no customer group is disadvantaged by an increased focus on digital services."

3.78 Power NI made no comment on Table 3.2 regarding existing Et items which UR determined should be retained, or deleted or the two new terms inserted.

3.79 In its response to the draft determination, Power NI asked that we make provision for further Et (pass-through) terms which it had not identified in its business plan submission:

- the ability to undertake research and development in the context of ensuring that the company is able to recover costs specific to energy transition to ensure customers have access to appropriate tariffs and products to allow efficient electricity usage as average consumption increases due to electrification;

- a general Et Term which allows for other unforecastable and uncontrollable occurrences, for example the increase from the UK Government in the form of changes to Employers NIC and National Living wages as it would be unreasonable for UR to expect Power NI to fully or partially absorb those type of costs; and,

- developing Network and Information Systems (NIS) requirements in respect of cyber security.

UR's response to the consultation comments in respect of additional Et terms

3.80 Regarding the changes proposed to the Et term in the draft determination, Power NI did not raise objections to the proposal and CCNI commented that full, detailed information and cost proposals would be required for the two new projects Therefore, UR intends to implement its original proposals and make the amendments to the licence set out in Table 3.2 above.

3.81 In the consultation on licence modifications, we have included additional wording in the definition of the additional Et terms for smart metering and digital engine to clarify that:

- An allowance will only be determined where the company is implementing a plan for the relevant project. We expect Power NI to set out its proposals in a plan and seek approval of its proposals in advance of incurring costs. We expect the company to prepare such a plan from within its general operating cost allowances.
- Any allowance determined will be net of any reduction in existing costs or projected costs arising from the implementation of the proposals. This will ensure that the company does not benefit from potential savings arising from the projects related to smart metering and the implementation of a digital engine while consumers bear the cost of implementation.
- An allowance will only be determined if the project is sufficiently material and has been justified in a submission to UR which is in such format and contains such information as may be specified by UR for that purpose (including demonstrating the need for the project and the costs, outputs and benefits). We expect the company to provide clear justification for the proposals it brings forward.

3.82 For the reasons set out in Table 3.3 below, we have decided not to include any of the additional Et terms requested by Power NI in response to the draft determination.

Et term identified by Power NI	UR response
Research and development	We are not convinced that an open Et term for research and development is either necessary or appropriate. The company can undertake general research and development within its determined cost allowance which are based on historical costs. The Et terms which cover the implementation of smart metering, and the development of a digital engine provide an opportunity for the company to seek development costs for these activities within the context of the qualifications in the licence term.
General term for other unforecastable and uncontrollable occurrences	We consider a general term for other unforecastable and unforeseeable cost to be too broad in scope. The current list of Et terms in the licence is intentionally specific. This avoids the risk that an open provision of Et terms becomes asymmetric with the company identifying events which increase costs but failing to identify events which reduce costs. The examples which the company identifies (changes in Employers NIC and National Living Wage) are costs which will be reflected, at least in part, in CPIH and additional allowances risk duplicating the general inflation mechanism of the licence. Our proposed cost sharing mechanism, limits the impact and risk of unforecastable and unforeseeable costs.
Network and Information Systems (NIS) development.	In the draft determination and following a significant conversation with and receipt of new information from Power NI, UR have allowed within FY25, the cost of the consultancy for Network & Information Systems (NIS) compliance. It was UR's view that the need for the rest of the planned NIS costs requested annually for the duration of the price control had not been sufficiently demonstrated and there are still too many uncertainties. In its business plan Power NI made submissions for £2.2m of additional IT costs. UR has allowed all of the other additional software forecast costs requested by the company on the basis that these costs allow provision for cyber security, data governance, new mobile apps, Privileged Access Management, Windows upgrade and Cloudflare. We have not ignored Power NI's legitimate claims regarding cyber security and associated software requirements. Furthermore, we understand the complexity of IT security within Power NI which reflects the evolving threat landscape and challenges which all companies face. We understand that infrastructure must defend against a myriad of cyber threats, from sophisticated malware to phishing attacks, all while ensuring seamless and secure access for legitimate customers, partners and employees. However, we have had no subsequent information that would change this decision or encourage UR to create an Et term for cost recovery of NIS at this stage.

Table 3.3: UR response to request to new Et terms

Additional issues raised by Power NI following its response to the draft determination.

3.83 Following receipt of its response to the draft determination, the company identified three further issues and asked UR to consider adding additional E_t terms to allow it to recover additional costs which might result, as follows:

- Future Arrangements for System Services (FASS) currently in development;
- the Renewable Electricity Support Scheme (RESS) currently being develop by the Department for the Economy; and,
- anticipated development of the Single Electricity Market.

3.84 UR recognises that each of these activities could have significant impact across the electricity sector, including for electricity suppliers. This could include additional investment in new systems, additional requirements for collateral and additional ongoing operational costs. However, all of these projects remain in the development stage, and it is not yet possible to fully understand their likely impact. In view of this, we have not included any further modifications in the price control in respect of these items. However, we remain open to introducing further licence modifications when the scope of changes and their impact on Power NI has been clarified if we consider that to be justified at the time in the light of all the information then available.

4. Operating Expenditure (Opex) and Other Costs

4.1 This section of the document sets out our final determination of Power NI's operating expenditure (Opex) determined allowances and other costs.

4.2 One of the principal areas of analysis in formulating our final determination for this price control has been the appropriate level of Opex which should be allowed for Power NI for the SPC25 Price Control period.

4.3 We initially anticipated that we would have a combined approach which would consist of "top-down" and "bottom-up" analysis. However, given the length of time since the last full price control along with inflationary and cost of living shocks in the last few years, we conducted a fuller line-by-line assessment of all costs within each of the Opex categories.

4.4 Prior to the submission of costs, UR and Power NI agreed that 2023/24 (FY24) would be the base year for the SPC25 Price Control as it was the nearest full year of actual costs to the start of the new price control. All costs in the final determination are in 2023/24 prices unless stated otherwise.

4.5 The current price control uses CPIH as the general measure of inflation which is applied to inflate determined values from base year prices when calculating the maximum allowed unit price of electricity in tariff year prices. We will continue to use CPIH as the general measure of inflation for the SPC25 Price Control.

4.6 Power NI has six categories of operating expenditure/cost provision:

- Salaries
- Materials and Bought in Services (MBIS)
- Outsourced IT and Software Costs (including Printing)
- Agency Costs
- Shared Services and IT Systems
- Bad Debt

4.7 Power NI provided UR with a detailed breakdown of each of the cost categories through a Business Efficiency Questionnaire (BEQ). This BEQ detailed each cost category with historical actual costs from FY18 to FY24, latest best estimates (LBE) for the financial year FY25 and forecast costs for the four years of the SPC25 Price Control from FY26 to FY29.

4.8 UR's price control team analysed the BEQ and established a query process with Power NI. The price control team reviewed each cost category and sought additional evidence and explanation from Power NI as to the quantum of costs and the constituent parts of these costs where they were not evidenced or obvious. UR engaged with Power NI particularly on the cost submissions made regarding salaries and IT.

4.9 Power NI forecast that its Opex would increase from FY24. The most significant projected increase was in FY25 which is the last year of the current price control and of the two-year Opex uplift agreement. A number of uplifts in individual Opex costs were projected for FY25, with forecast costs then remaining relatively static or in some cases decreasing during the four-year duration of the SPC25 Price Control.

FY25 Opex Proposals

4.10 Table 4.1 shows Power NI's forecast Opex costs for FY25 and UR's position on these in the draft determination. Following assessment of Power NI's FY25 forecast costs, UR has made some adjustments to the salaries and outsourced cost categories as outlined below, resulting in a 2.0% reduction of £668k in the Net Opex (including RoI recharge) for FY25. **The proposed Net Opex for FY25 with these adjustments is £39.795m.** Changes to forecast costs are highlighted in green text in Table 4.1 and all costs are in the 23/24 price base.

Cost Category	POWER NI forecast £m	UR determined £m	Difference £m
	FY25	**FY25**	**FY25**
Salaries	17.613	17.218	-0.395
Materials	3.681	3.681	-
Total Bad Debt	1.622	1.622	-
Outsourced IT and Software	7.696	7.423	-0.273
Agents (PPM)	3.750	3.750	-
Shared IT Systems	3.922	3.922	-
Shared Services	0.353	0.353	-
ROI recharge	1.826	1.826	-
Net Opex including RoI recharge[12] (excluding pass through and depreciation)	40.463	39.795	**-0.668**

Table 4.1: Power NI forecast, and UR proposed Opex costs for FY25

[12] These are forecast costs taken from the BEQ but are likely to change once the outcome of the

4.11 **Salaries** - an additional 27.8 average Full Time Equivalents (FTE)[13] were forecast in FY25. UR had discussed these requests with Power NI and in the draft determination stated our intention not to allow 7.8 additional FTEs. This equates to a reduction of £395k (in 23/24 prices) for FY25. Further information on the reason for these adjustments can be found below.

4.12 **Outsourced IT and Software** - an additional uplift amount of £2.2 million was requested that includes implementation and licensing costs for cyber security, data governance, software and compliance. UR had discussed these requests with Power NI and proposed in the draft determination to allow costs with one adjustment. This equates to a reduction of £273k (in 23/24 prices) for FY25. Further information on the reason for these adjustments can be found below.

4.13 Since the draft determination was published Power NI has provided its latest best estimate for FY25 to UR. The company has underspent in FY25 compared to the forecast in its business plan. Its forecast Opex was £40.5m for FY2025. The actual outturn for FY25 is £35.129m. Power NI had forecast that its average FTE for FY25 would be 328.5, however, the actual outturn for the year was 312. The reason for the difference was that expected recruitment has been delayed due to limited capacity for these processes to be undertaken while the business is focused on the price control process and the large-scale billing system upgrade. A pause on recruitment during the later part of the year, due to the Energia Group sale process, has also led to several planned roles not yet being filled. UR appreciates that the recruitment freeze and other barriers in recruitment means that some roles still need to be filled and so we intend to retain our draft determination position.

4.14 The difference in IT has resulted from several large-scale IT software projects which were to begin in early FY25 being delayed primarily because the IT teams have needed to focus resources on other projects and compliance related activity, e.g., the CC&B upgrade and the Group sale process. Other factors include delays in receiving clarification on scope of regulation and frameworks (e.g. NIS2), personnel change in the IT security team, review of strategic direction for customer engagement and technologies considering rapidly progressing IT and AI landscape. The company now expects that these elements will commence in FY26.

Gemserv review is finalised.

[13] Full Time Equivalent or FTE is a unit of measurement used to show the number of full-time hours worked by all employees in an organisation. In the UK, a standard work week of 40 hours has an FTE value of 1.0. The number of FTE will often differ from the number of staff employed (the organisational headcount) as not all staff will work full-time hours. For example, at 31 March FY24, Power NI had an FTE of 312 but had an organisational headcount of 357 (based on a standard work week of 37 hours).

4.15 The biggest differences are within software maintenance and strategic projects where the company spent £1.8m less and £1.1m less respectively on IT managed services and software as a service compared to the forecast. These are projects which we have deemed essential to the secure running of the business. Therefore, it is our intention to retain our draft determination position.

FY26-FY29 Price Control Determinations

4.16 Table 4.2 details the forecast costs for FY25 and the final determined costs for each year of the SPC25 Price Control. Following assessment of Power NI's forecast costs for the price control period, UR has made adjustments to the salaries and outsourced IT and software costs as outlined below. These adjustments largely reflected UR's forecast decisions for FY25 carried forward into the price control period and result in an annual 2.0% reduction of £795k. This equates to a total reduction of £3.18m in Net Opex across the four-year SPC25 Price Control period. **The total value of the Net Opex for SPC25 Price Control using UR's final determined costs is £152m.** Changes to forecast costs are highlighted in green text and all costs are in the 23/24 prices.

Cost Category	UR PROPOSED COSTS (£m)				
	FY25	FY26	FY27	FY28	FY29
Salaries	17.218	17.502	17.650	17.667	17.651
Materials	3.681	3.474	3.326	3.448	3.321
Total Bad Debt	1.622	1.682	1.785	1.899	2.003
Outsourced IT and Software	7.423	7.383	7.226	6.459	6.423
Agents (PPM)	3.750	3.497	3.573	3.590	3.665
Shared IT Systems	3.922	4.394	4.310	3.699	3.663
Shared Services	0.353	0.685	0.896	0.718	0.831
Net Opex (excl. ROI recharge, pass through and depreciation)	**37.969**	**38.617**	**38.766**	**37.48**	**37.557**
RoI recharge[14]	1.826	1.926	2.036	2.149	2.231
Gross Opex (excl. pass through)	39.795	40.543	40.802	39.629	39.788
Pass through costs	0.835	0.835	0.835	0.835	0.835
Opex Gross (excluding depreciation)	40.630	41.378	41.637	40.464	40.623
Total Depreciation[15]	2.221	3.667	3.759	3.804	3.552
-Depreciation through Et -Depreciation through Pf	(1.249) 0.972	(2.504) 1.163	(2.787) 0.972	(2.955) 0.849	(2.733) 0.818
Opex Gross excl. depreciation recovered in Et	40.63	41.378	41.637	40.464	40.623
Amounts recovered through Pf -Gross Opex excl. passthrough - Depreciation through Pf **Total Pf[16]**	 39.795 0.972 **40.767**	 40.543 1.163 **41.706**	 40.802 0.972 **41.774**	 39.629 0.894 **40.478**	 39.788 0.818 **40.606**

Table 4.2: UR Proposed Opex Costs for FY25 and FY26-FY29

- **Salaries –** costs show minor increases during the price control due to annual salary increases and a projected reduction in frontline FTE. UR has adjusted the salaries costs by £395k for each year of the price control period.
- **Outsourced IT and Software -** costs are higher in the first two years of the Price Control and reduce again from FY28 onwards. UR has adjusted the outsourced IT and software costs for the price control period and has removed

[14] These are forecast costs taken from the BEQ but are likely to change once the outcome of the Gemserv review is finalised.
[15] These are forecast costs taken from the BEQ but are likely to change once the outcome of the Gemserv CC&B review is finalised. Additionally, Power NI has yet to bring forward proposals for Digital Engine and the basket of costs associated with those depreciated through Pf.
[16] This total is based on determined and forecast costs and are subject to change

costs of £400k per year for one category. Further information on the reason for these adjustments can be found below.

- **Cost Sharing Mechanism** - UR intends to introduce a symmetrical 35:65 cost risk sharing mechanism across all Opex categories, to promote efficiency for the duration of the SPC25 Price Control. It is our intention to focus on the total allowance (£41.139m/a) vs total actuals and apply the cost sharing mechanism to that difference on an annual basis. We will not be concerned with a line-by-line analysis of an over and underspend within each line of each Opex item. While we reserve the right to examine costs where there are significant differences, it is not our intention to conduct a bottom-up analysis annually.

4.17 At this time, and in the absence of more up to date information we have used the forecast costs as a placeholder for RoI recharge. We have no further updated information on the RoI recharge at the time of writing of this final determination. In its response Power NI made no comment on the other intangibles, or any other costs. Hence, they have not been revised in this final determination.

Response to draft determination – Opex overall

Power NI Response

4.18 In its response to the draft determination Power NI stated that UR has, in conducting a bottom-up line by line analysis of the business plan submission has, not allowed for minor variances. It also contended that UR did not fully utilise the Baringa report which Power NI state clearly demonstrates that Power NI is currently and, based on the forecast Opex over the next four-years, will continue to be an efficient business.

UR Response

4.19 In the analysis of the company's business plan UR gave due consideration to the Baringa report and amended two of the six categories of Opex. UR acknowledged in the draft determination that, in most cases, costs forecast are necessary for the running of the business. UR disagrees with Power NI regarding our bottom-up approach. In our view, it has been more than 10 years since the last full price control and analysis at this level proved necessary. The line-by-line analysis allowed UR to gain a deeper appreciation of the complexity of the business which demonstrated that in the round most Opex costs were reasonable. This allowed UR to accept many categories and individual lines of cost without contest as the specific cost drivers were fully demonstrated.

4.20 In our approach we had considered moving Agency (PPM) and Bad Debt from St to Et (pass through). Power NI responded to the suggestion that we may move these allowances into the Et (pass through) by stating, *"... on the potential movement of PPM and Bad Debt into ET – we would strongly object to this being moved across. The exclusion from St removes the incentive to outperform allowances which are subsequently harvested in the interests of customers, so feel it should stay as is."*

4.21 Having carefully considered Power NI representations we decided to retain these allowances in the Opex. This will enable Power NI to make efficiencies in these categories and gain 35% through the cost sharing mechanism which would not have been the case if these items had been moved to Et terms.

Salaries

4.22 Over the price control period, Salaries costs are forecast to change very little throughout the price control in real terms with a small reduction in actual staff numbers.

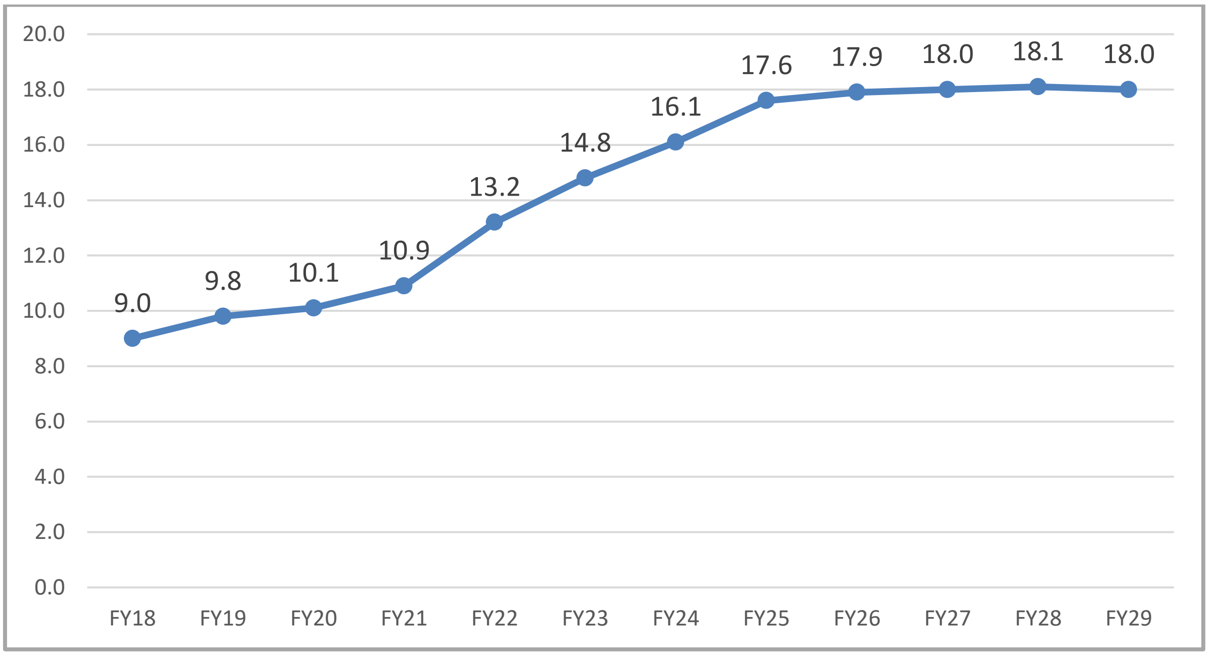

Figure 4-1: Salaries actual and forecast costs FY18-FY29 (£m)

4.23 Salaries had been forecast to increase in real terms from £16.1m to £17.6m in FY25 due to increased FTEs - including new roles - and payment of annual pay awards and bonuses including living wage increases for staff at the lower end of pay scales. Based on average FTE numbers, Power NI had forecast an increase of 27.8 FTE in FY25, with the majority of these increases set to be maintained during the price control period. As stated in Paragraph 4.13 Power NI has underspent compared to its forecast and average FTEs at the end of FY25 (which formed the basis for its SPC25 Price Control projections) were 312 compared to the forecast 328.5.

4.24 During the price control period, Power NI has forecast that salary costs will increase at a low steady rate due to annual pay awards and bonuses including living wage increases for staff at the lower end of pay scales. A reduction of 8.1 FTE between FY26 and FY29 has been forecast due to anticipated headcount reductions in the Contact Centre. All other teams (except Billing) are projected to maintain FY25 FTE levels. Power NI assume that going forward, the peak energy crisis will abate to a degree and that there will be a reduction in the headcount required in the Contact Centre as the situation normalises and frontline call volumes reduce. There is also a growing focus on maximising self-service options. Currently, self-serve accounts for approximately 10% of all Power NI contacts, with plans to expand the offer as the energy transition evolves, and digitalisation of services increases. This will further reduce the demand on Contact Centre staff.

FTE Reduction

4.25 Power NI stated that the forecast FTE increase in FY25 consists of backfill for one vacant role, eighteen new roles and FTE uplift for existing roles/teams. FTE increases are offset slightly by forecast FTE reductions in some frontline teams e.g. Contact Centre and Billing. Power NI stated that the FTE increase will allow it to maintain its industry leading standards of customer service, efficiency, innovation, and best practice as the dominant electricity supplier in Northern Ireland. However, for reasons already stated the forecast FY25 average FTEs did not materialise.

4.26 In this final determination UR has not changed its view and intends not to allow the 7.8 FTE in the price control period. This is a reduction of FTEs from Power NI's closing FY24 forecasts and equates to an Opex reduction of £395k for each year of the price control (in 23/24 prices).

4.27 UR determined salaries allowances for SPC25 were calculated by subtracting the FY24 average FTE cost for the additional roles that have not been allowed from the forecast salary costs. FY24 average FTE costs have been used to calculate the disallowed amount for salaries, rather than future forecast costs, as future costs include salaries for staff that have not been allowed in the price control, some of whom were at a more senior level attracting higher salaries. Overall, we take the view that, where the company has identified 'vacant' roles in its staff structure, this is not sufficient evidence that these roles should be funded in the next price control. Instead, we will always place more weight on the actual current costs of the business, recognising that any organisation is in a continuous state of flux and there will always be some vacant roles in its current staffing. We note that the company has decided to discharge its functions within its current cost base without these roles in place. The following roles have not been allowed:

4.28 **Sales and Retention:** At the close of FY24 the Sales and Retention team had 32.0 FTE, and this was forecast to increase to 33.8 in 2025. UR intends not to allow this increase of 1.8 FTE for the following reasons. Power NI has seen strong growth in customer numbers in recent years and at December 2024[17], they held a domestic market share (by connections) of 60.9%, dominating both the credit and prepayment sectors in Northern Ireland. The recent announcement of Electric Ireland's withdrawal from the domestic supply market in Northern Ireland will potentially increase Power NI's market share even further. UR further assess that multiple new entrants to the supply market in the coming years are unlikely due to the relatively small size and increasing saturation of the Northern Ireland market. That said, there has been some shift in the market with Share Energy entering the Northern Ireland domestic market in September 2024. To date Share Energy has less than 1% market share. While Power NI may have awareness of another entrant to the market in 2025 it is too early to ascertain what, if any, impact it will have on Power NI's market share.

Response to draft determination – FTEs

Power NI Response to the draft determination

4.29 Power NI, in its response to the draft determination, argued that there is increased competition and intensity in the market which will require additional staff. It also stated that switching rates have increased with the introduction of Share Energy and mentioned another new entrant into the NI supply market in 2025. Power NI stated that the additional staff needed will help to manage increase churn in the market while reminding UR of its statutory obligation to promote competition.

UR Response

4.30 In the latest QREMM report Q4-2024 Power NI has 60% of the domestic market and this has been increasing with SSE being Power NI's nearest competitor with 17% of the market. At this point there is no evidence of increasing churn or that the new entrant has made an impact. Power NI, in its response to UR's draft determination, states that switching rates have increased with the introduction of Share Energy. As already mentioned,

[17] Q3 QREMM 2024 (https://www.uregni.gov.uk/publications/remm-transparency-reports-2024

Share Energy has less than 1% of the domestic market and the impact of a new entrant remains to be seen.

4.31 Quarter 4 2024 QREMM figures suggest that switching figures appear to be declining and stabilising after the increased and unprecedented level of switching observed during the cost-of-living crisis. Figure 4.2 below details the actual number of customers switching in the domestic market monthly since 2023 by type of customer.

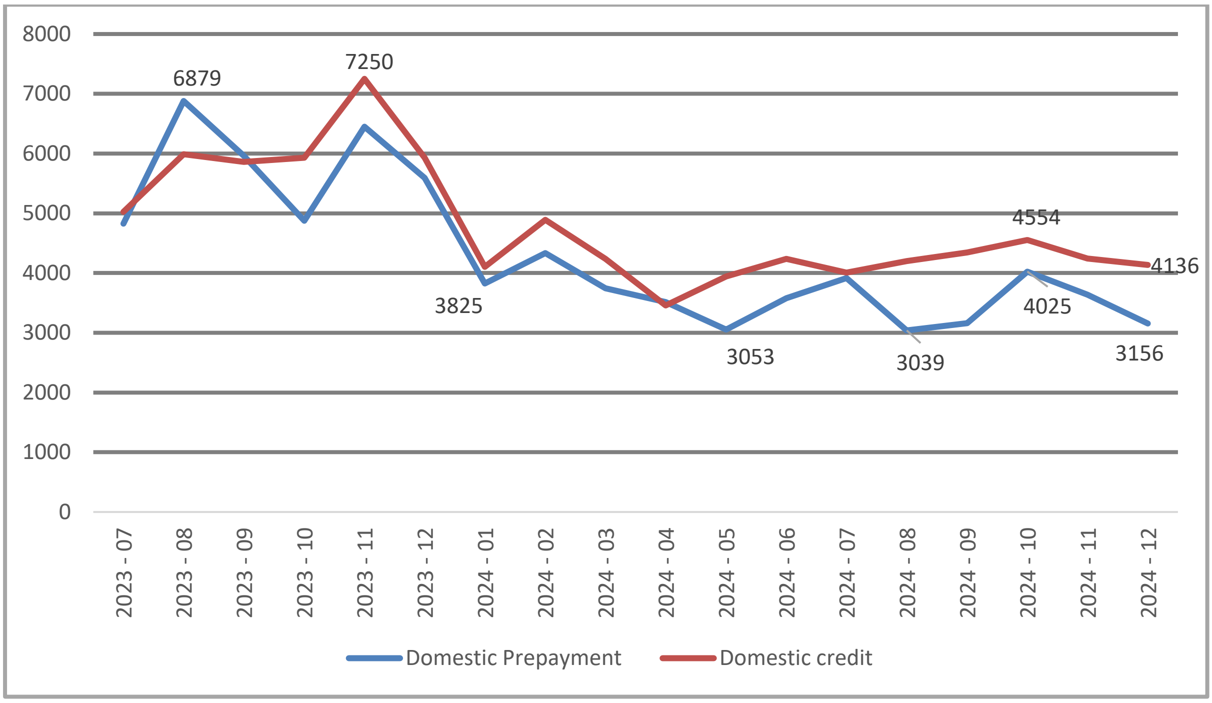

Figure 4.2: Monthly domestic switching rates 2023-2024

4.32 Similarly, Figure 4.3 details the percentage quarterly change from 2020 to Q4 2024.

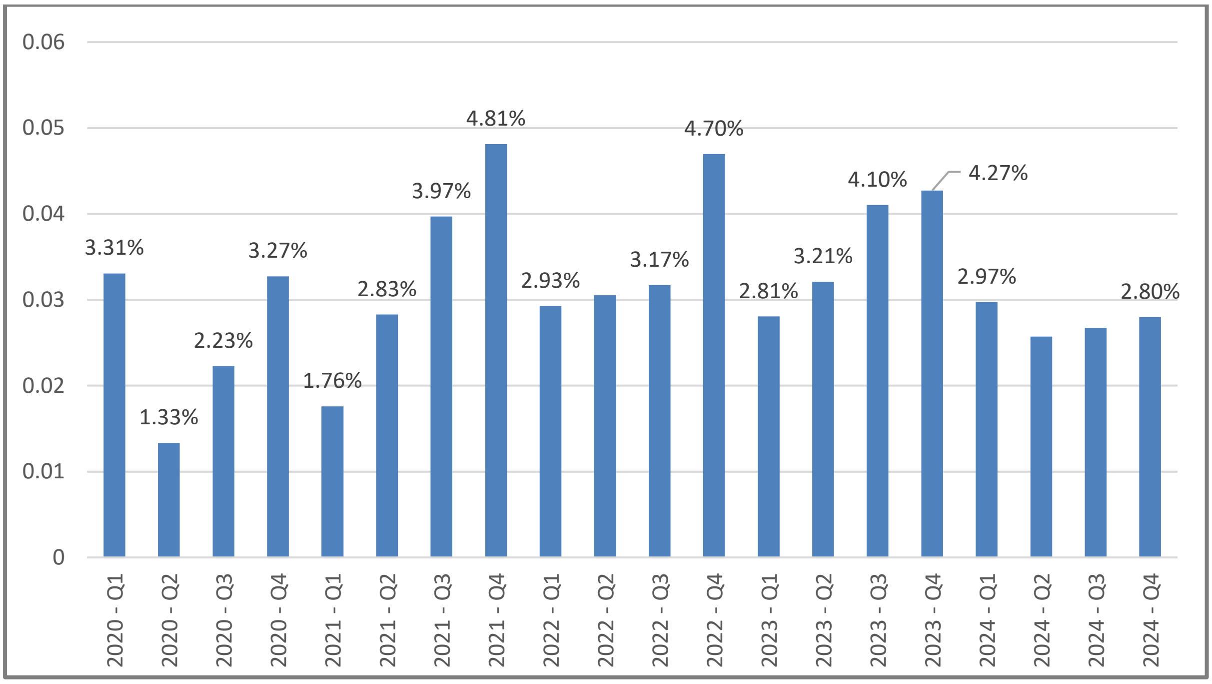

Figure 4.3: Quarterly switching rates 2020-2024

4.33 During 2020 COVID, switching was lower as prices were significantly lower, while there were higher levels of switching at the end of Q4 2022 and again at end of 2023 due to the cost-of-living crisis, throughout 2024 switching levels have stabilised and in fact the usual Q4 increase in switching previously observed is not evident in 2024. Through 2024 there has been a more stable switching rate.

4.34 Having reviewed Power NI's submission, UR has **not** changed its view and intends not to allow the 1.8 FTE in sales and retention.

4.35 **Finance**: UR intends **not** to allow the new **Technical Reporting Accountant** role as requirements mainly appear to be anticipatory rather than mandatory and reporting appears to be for internal or Group information. We understand that these requirements remain uncertain. Roles with a significant amount of Group requirements and/or to provide additional insight to stakeholders/ those who have an interest in Power NI have not been allowed. We are of the view that an efficient company would have sufficient internal resources to provide this information and still consider that Power NI customers should not bear the cost of this role.

4.36 UR intends **not** to allow a new **Projects and Change Business Analyst** role as this involves a significant amount of work on behalf of Group as well as procurement work which it is assessed can be covered by existing resource. While the introduction of the new Procurement Act will require a resource commitment for initial training and navigating teething problems, it is anticipated that the new system will streamline procurement processes in the longer term.

4.37 UR intends **not** to allow a new **Graduate Trainee** role as this is not a mandatory role and has been suppressed in recent years.

4.38 UR intends not to allow backfill of one role in the **Qlikview Team** as this team has been successfully functioning at or below the FY24 average FTE level for a number of years and the need for backfill, particularly at a Senior level which attracts a higher cost, has not been sufficiently demonstrated. Power NI stated in its response to the draft determination that UR had misunderstood the nature of this role, but we are satisfied that this is not correct. We remain of the view that recruitment of a more senior individual was not sufficiently demonstrated.

4.39 **Trading**: Having sought advice on the forecast FTE in Trading due to the specialised nature of this work area. UR intends **not** to allow a new Analyst role for Trading Operations. We had already stated that as Power NI trades predominantly in the Day Ahead Market (DAM) it is assessed that the increase in Intra-Day Trading markets from four to six will not have a significant impact on the business. Further to this, having reviewed the points made by Power NI in its response to the draft determination, UR is still of the view that the need has not been adequately demonstrated. We expect the majority of the Celtic Interconnector volumes to be traded in the DAM. Moreover, we would be of the view that while suppliers will continue to be most active in the SDAC, IDA1 and EUIDA1 markets from go-live, these are within (or just after) normal working hours. We appreciate that there may be changes after go-live of the Celtic Interconnector, however, we would expect these changes will emerge over time and not happen overnight. We intend **not** to allow this role.

4.40 **Customer Value Maximisation**: One new Manager role was forecast. UR intends not to allow this new role as Power NI has not provided specific details of the ways in which customer behaviour has changed and how these changes directly translate to this additional role. In addition, the reason for recruitment of an individual at a more senior level has not been demonstrated. Power NI stated in its response to the draft determination that UR had misunderstood the nature of this role and that it is not driven by ways in which customer behaviour has changed. We disagree as the customer journey is driven by behaviour. In the draft determination, UR was of the view that recruitment of a more senior individual was not sufficiently demonstrated, our view has not changed.

4.41 **Overall**: It has also been noted that FY2025 closed at 312 average FTEs against a forecast of 328.7. While we are not allowing 7.8 FTEs, we determine that the allowance is still sufficient and provides Power NI with an appropriate and sufficient allowance within the price control. We understand that expected recruitment has been delayed while certain large-scale projects are underway along with a pause in recruitment due to the Group sale process. However, it is expected that recruitment will happen in FY2026, and UR would expect an efficient company to operate within the allowance provided for within the price control.

Materials and Bought in Services (MBIS)

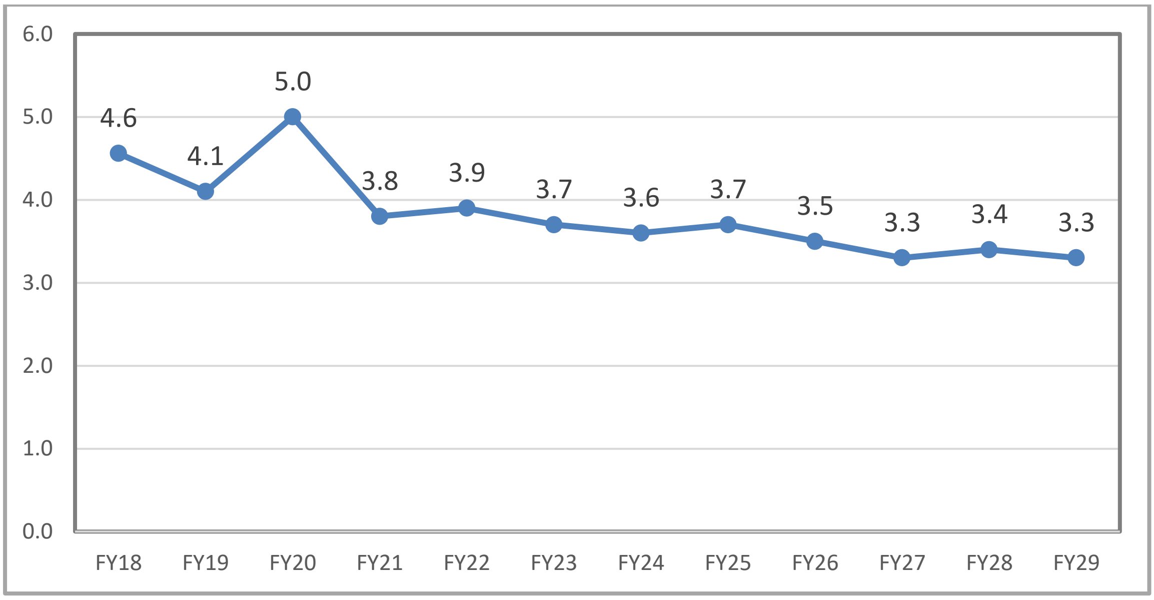

Figure 4.4: MBIS actual and forecast costs FY18-FY29 (£m)

4.42 Over the price control period, Materials costs are forecast to reduce from £3.7m in FY25 to £3.3m in FY29, with an average annual cost of £3.4m. Since 2022, Power NI reports that Materials costs have been falling in real terms, and they are forecast to continue to decrease during the price control. These decreases are driven largely by a reduction in legal and professional costs and non-payroll staff costs.

4.43 Forecast MBIS costs are consistent with Power NI's historical costs and are relatively unchanged for the duration of the price control. All costs are necessary for the running of the business.

4.44 Following scrutiny of the costs UR intends to allow forecast MBIS costs.

Bad Debt

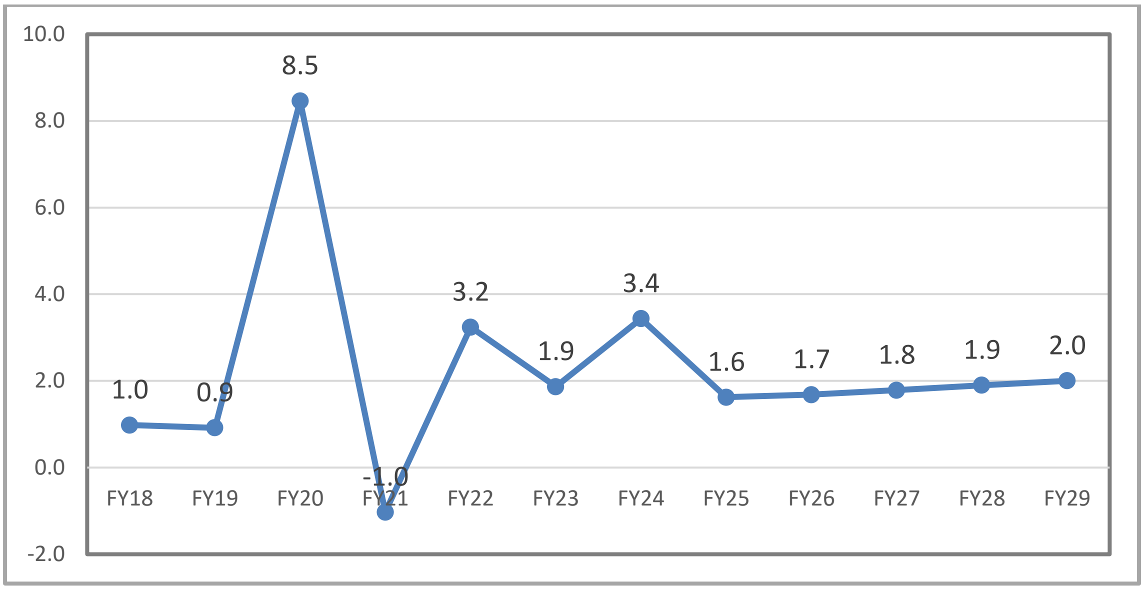

Figure 4.5: Bad Debt actual and forecast costs FY18-FY29 (£m)

4.45 Within the price control, Bad Debt is forecast to increase only very slightly each year in real terms. As actual write offs are forecast to remain around the same level of £0.4-0.5m per year from FY25, these increases are due to a small amount of anticipated upward annual movement in the provision. Despite reduced market volatility and decreases in wholesale energy prices and inflation, consumer tariffs remain significantly higher than prior to the cost of energy and living crises.

4.46 UR intends to allow forecast Bad Debt costs and will not be moving Bad Debt from an ex-ante allowance in the **S_t term** of the licence to an allowance for actual bad debt write-offs recovered through the **E_t (pass through) term**.

4.47 UR has assessed that maintenance of current staffing levels in the Debt team during the price control period will assist with mitigating the risk of bad debt, and the number of prepayment meter customers is forecast to maintain at around 39% of all residential customers, further reducing potential bad debt exposure.

Outsourced IT and Software (including printing)

4.48 Outsourced IT and Software costs are forecast to increase in real terms from £4.6m in FY24 to £7.7m in FY25. This is due to projected increases in Software including strategic projects costs and – to a lesser extent – Managed Service and Software as-a-Service costs.

4.49 Outsourced costs are then forecast to remain relatively steady in real terms in the first half of the price control before reducing in FY28 and FY29. This reduction in the second half of the price control equates to a 12.8% cost reduction from FY26 to FY29 and is due to anticipated decreases in strategic projects costs in FY28 and FY29 following a period of increase due to implementation of the SAP Hana finance system upgrade in FY26 and FY27.

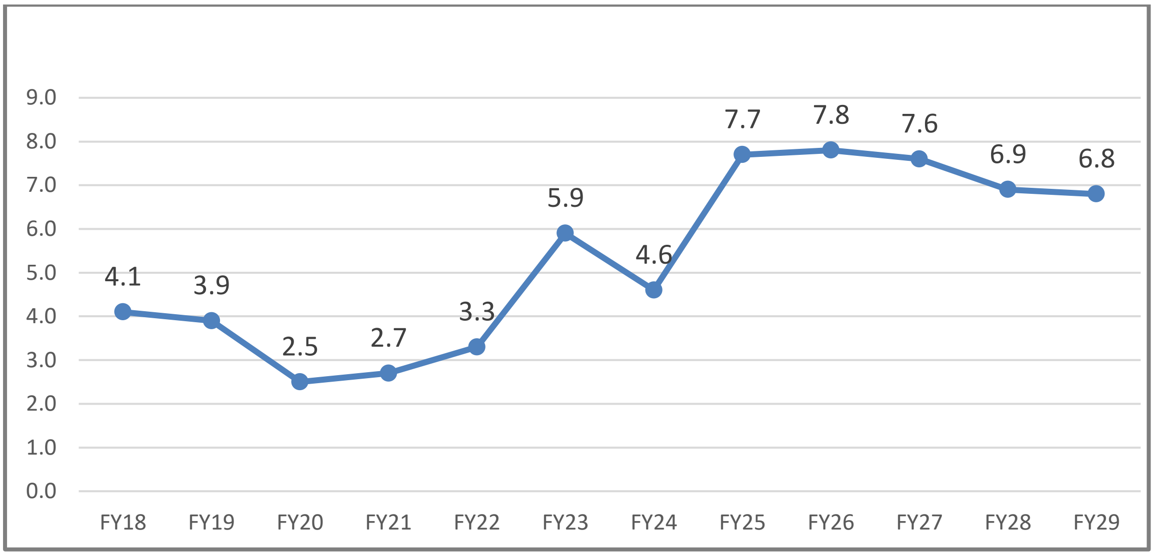

Figure 4.6: Outsourced actual and forecast costs FY18-FY29 (£m)

4.50 Power NI has included an additional uplift amount of £2.2m for software in FY25 which is maintained throughout each year of the price control period FY26-FY29. All the software that Power NI is requesting allowances for relates to enhancing systems, data governance/compliance and important cyber security systems.

4.51 Costs are based on an outsourced implementation charge, software costs plus third-party markup, and ongoing licensing fees each year. A summary is shown in Table 4.3 below:

(2023-24 prices)	FY25 £000s	FY26 £000s	FY27 £000s	FY28 £000s	FY29 £000s	Total
Implementation	£765	£750		£304	£298	**£2,117**
Recurring	£1,616	£1,615	£1,615	£1,616	£1,615	**£8,077**
Total	**£2,381**	**£2,365**	**£1,615**	**£1,919**	**£1,913**	**£10,194**

Table 4.3: Additional IT uplift implementation and recurring costs FY25-FY29

4.52 UR held discussions with Head of IT Systems and Head of Strategy and Architecture for Energia. As a result, additional information has been provided regarding the costs of the requested systems. We have also applied our own experience in IT systems and price controls and were satisfied that the requested allowances were within an acceptable limit of the activities required with one exception.

a) UR in discussions with IT and finance experts has verified that the consultancy cost for mandatory Network and Information Systems (NIS)[18] compliance requirements in FY25 seems appropriate but that this would not need to be a recurring annual cost. Furthermore, it is assessed that the planned use of the remainder of NIS forecast costs for FY25 and the price control period has not been sufficiently demonstrated by Power NI.

b) UR intends to allow Outsourced IT and Software costs for FY25 and the SPC25 Price Control period **except for NIS Compliance costs which are capped at a one-off in FY25 of £127k.**

c) UR intended Outsourced allowance for FY25 has been calculated by subtracting the difference between NIS consultancy costs (£127k) and overall forecast NIS costs (£400k) from the forecast FY25 outsourced costs. For the price control period, all NIS costs (£400k annually in 23/24 prices) have been subtracted from the forecast outsourced costs.

Response to draft determination – IT cost

Power NI Response to the draft determination – IT costs

4.53 Within its response to the draft determination, Power NI has suggested that UR allows a new Et term linked to the NIS requirements. We have dealt with the reasons for not including a new Et term in Table 3.3 above.

UR response – IT Costs

4.54 In addition to that we would expect that Power NI is reviewing its internal processes and third-party contracts to ensure that they meet the current regulations and any upcoming future changes/ revisions. Power NI has not provided an additional background for the need for the funding over and above what would be considered business as usual activities. In our discussions prior to publication of the draft determination, Power NI could have provided a detailed, fully costed proposal. Furthermore, it would be expected that any future IT system should be developed in line with the current regulations and so should already be compliant with the Directive.

4.55 The NIS Directives places obligations on businesses to strengthen cybersecurity, audit regularly and report incidents swiftly. It typically covers areas like risk management, security policies, incident response, the need to

[18] Network and Information Services (NIS) is a mandated compliance requirement from the Department of Finance for all operators of essential services such as Power NI.

identify gaps in current security measures and develop a plan for improvement and more. The Northern Ireland NIS Competent Authority provides guidance to aid Operators of Essential Services to ensure understanding of and compliance with the Directive. We would encourage the company to upskill staff for inhouse internal auditing to ensure ongoing compliance. We would also expect that current and future systems installed would be targeted for compliance automatically and software providers would ensure system compliance and monitoring. We understand from conversations with Power NI that it is aware of the risks and threats to its systems and already follow good cyber security practices. We would expect Power NI as an Operator of Essential Services to have implemented appropriate technical and organisational measures to manage cybersecurity risks as a business-as-usual function within its ongoing activities.

Printing

4.56 Also, within this Opex category the costs of printing are included. In the SPC25 Final Approach, UR stated that it was considering moving Printing Payment and Mailing costs from an ex-ante allowance in the **S_t term** of the licence to recovery through the **E_t (pass through) term**, based on actual costs or an ex-post volume driven allowance. Specifically in relation to Printing, Power NI forecast a continued reduction in costs in FY25 and into the price control period. In the pre-existing price control these costs were covered by the 2022 cost sharing mechanism that allows Power NI to retain 35% of any PPM efficiency savings and return 65% back to the customer. This specific cost sharing mechanism ended on 31 March 2025. It should be noted that to date this has returned c.£2m to the customer while Power NI has retained c.£1.1m.

4.57 The continued decrease in Printing costs is a strong driver for retaining these costs in the **S_t term**. In addition, Power NI is moving towards paperless billing. This will reduce printing costs further as capability embeds and more customers hopefully choose to go paperless. While a cohort of customers will prefer or require more traditional forms of written communication, demand in this area is likely to decrease going forward. Furthermore, the further development of customer facing apps, should reduce the need for printing. For these reasons, UR intends to retain Printing, Payment Providers and Mailing in the **S_t term.**

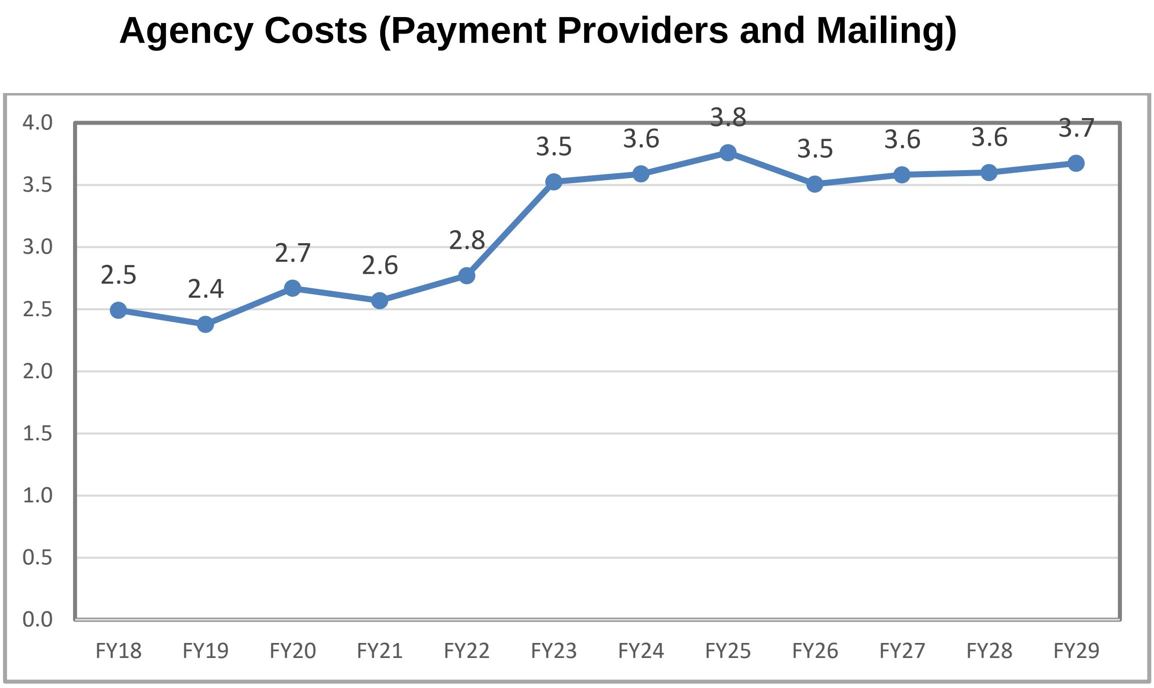

Figure 4.7: Total Payment Provider and Mailing actual and forecast costs FY18-FY29 (£m)

4.58 Over the duration of the price control Power NI forecast that Payment Providers and Mailing costs will initially decrease to £3.5m in FY26 before steadily increasing to £3.7m in FY29. Drivers for the increase include increased Power NI customer numbers, increased processing costs from payment providers, and increased postage costs as a result of Royal Mail price increases.

4.59 UR intends to allow proposed forecast Agency costs and will not be moving PPM costs from an ex-ante allowance in the **S_t term** of the licence to recovery through the **E_t (pass through) term**, based on actual costs or an ex-post volume driven allowance.

Shared IT Systems and Shared Services

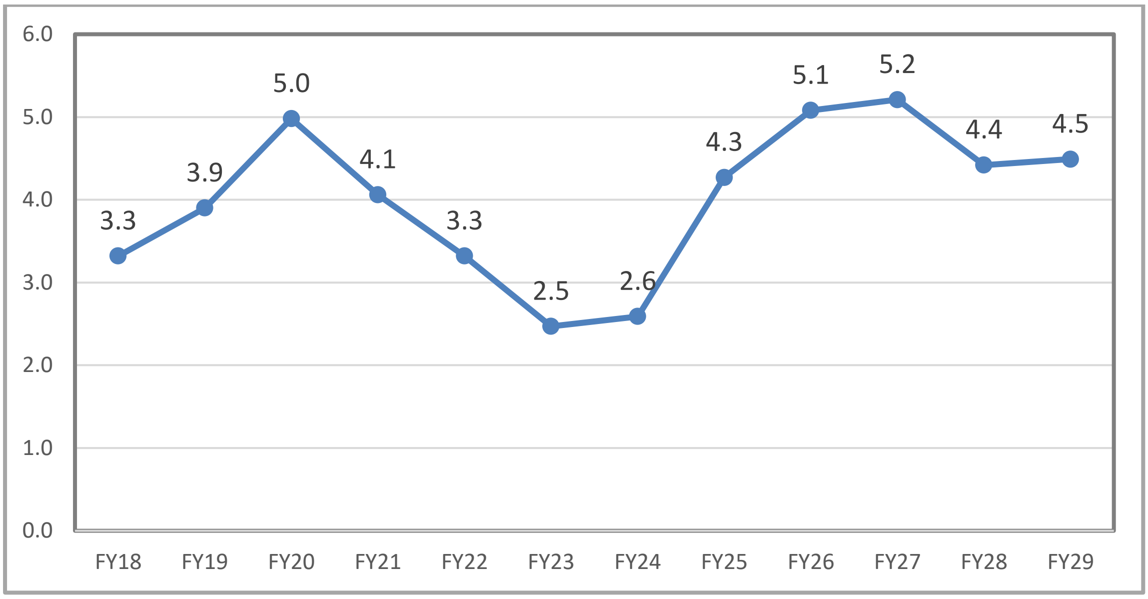

Figure 4.8: Total IT Systems and Shared Services actual and forecast costs FY18-FY29 (£m)

4.60 The regulated part of Power NI shares other resources with the non-regulated parts of the business and the wider Energia Group. Power NI's share of shared HR and other staff are included under Salaries costs and have been considered there. Within Shared IT Staff and Systems and Shared Non-staff Services there are recharged credit amounts received by the regulated (domestic) part of Power NI's business from Energia and the deregulated (commercial) part of Power NI's business for use of services owned by the regulated part e.g. Power NI's CC&B system. This has been taken into account to reflect the true cost of the Total Shared IT Systems and Shared Non-Staff Services.

4.61 UR intends to allow forecast Shared IT Systems and Shared Services costs.

Depreciation

4.62 Depreciation costs consist of the annual total of monthly depreciation and amortisation instalments to pay back monies used for expenditure on tangible and intangible assets and projects. Payback periods are calculated depending on the nature of the asset and reflect their likely useful economic life. Tangible assets are generally physical assets such as buildings and fixtures and are depreciated over three years. Intangible assets are generally non-physical or digital assets such as IT systems and are amortised over five years.

4.63 Depreciation costs are forecast by Power NI to increase in real terms from £2.2m in FY25 to £3.7m in FY26. Costs are then projected to rise slightly each year to FY28 before reducing in FY29 but remain at a generally similar level during the price control period.

4.64 The assets and projects included in Depreciation costs include the following:

a) Tangible assets

- Fixtures and Fittings – refurbishment of the Omagh site in FY25.
- Other Tangible – laptop and server costs.

b) Intangible assets

(i) **CC&B upgrade**. The cost of the CC&B upgrade is currently being reviewed, and we are awaiting the outcome of that with regard to the costs associated with the new system. Power NI has forecast that the next CC&B upgrade is forecast to start being depreciated in FY29. We are of the view that including depreciation forecast costs for the commencement of a second upgrade within the FY26-29 price control period to would be premature.

(ii) **I-SEM (Endur system)** – the main asset was fully depreciated in FY24, and the remaining balance relates to the later enhancements due to potential market changes. We are content with these costs.

(iii) **Digital Engine** – UR will require a proposal for this project. It is expected that this project may include development of apps, systems integrations or digital sustainability as the energy transition progresses. However, to date UR has not been furnished with any information on this project. It will be necessary for UR to allow these costs subject to a detailed proposal on the nature and scope of the project and it would require a detailed programme of deliverables and detailed associated costs. Power NI will also be required to demonstrate that this project is in the interest of its regulated customers.

(iv) **Other Intangible** – these costs include a variety of smaller projects. Costs between FY27 and FY29 are mainly for smart readiness. We have already indicated in our approach paper and consultation that this price control would not include provision for smart meters. However, at this time we have split Other Intangibles. In FY26 we have assumed that the other intangible amount is a basket of smaller projects, and this will be recovered through the Pf term. Power NI has indicated that the depreciation amounts for other intangibles from 2027-29 are for smart readiness and so will be recovered through the new Et term which we have decided to create. However, we will require Power NI to provide further information on the content of Other Intangibles and to provide UR with a detailed proposal of the smart meter readiness proposal for approval which details the nature, scope and deliverables and how this will be of benefit to its regulated customers.

4.65 Depreciation for the price control period will be recovered through a combination of pass-through terms in the E_t term and through the Pf term. Where appropriate these will be adjusted via the A_t.

4.66 For the avoidance of doubt, within the current Et terms, term (h) allows for recovering depreciation costs for the CC&B upgrade, (CC&B), term (g) for recovery of the depreciation of the Endur system. We have decided to create an additional Et term to cover the Digital Engine depreciation costs and a new term for smart readiness, as already described above. The table below details how the depreciation cost will be allocated between $\mathbf{P_f}$ and $\mathbf{E_t}$ terms.

(2023-24 prices)	FY26 £m	FY27 £m	FY28 £m	FY29 £m
Et terms				
CC&B	1.483	1.461	1.437	1.409
ISEM	0.061	0.049	0.045	0.041
Digital Engine	0.961	1.278	1.472	1.283
Other Intangible	0.000	0.000	0.000	0.000
Total Et	**2.504**	**2.787**	**2.955**	**2.733**
Pf term				
Other Intangible	0.750	0.619	0.512	0.502
Fixtures and Fittings	0.024	0.022	0.019	0.018
Other Tangible	0.203	0.148	0.137	0.135
Lease	0.186	0.183	0.181	0.164
Total Pf	**1.163**	**0.972**	**0.849**	**0.819**
Total Depreciation	**3.667**	**3.759**	**3.804**	**3.552**

Table 4.4: Depreciation amounts through Et and Pf

4.67 The SPC25 margin has been calculated to cover the cost of financing the fixed assets detailed in the depreciation calculations with effect from 1 April 2025 and therefore going forward there will be no need for a separate rate of return allowance/ separate Regulated Asset Base (RAB) calculation from this point onwards.

4.68 If during the price control there is any large, unforeseen Capex we would enter into discussions with Power NI with regards to the best mechanism to recover those capital costs. This may be through a RAB calculation with a rate of return of the agreed Weighted Average Cost of Capital.

RoI Recharge

4.69 Within the Opex is an amount each year for RoI recharge which refers to the domestic Energia customers who are serviced via Power NI's CC&B system and for which Power NI receives a cost per customer from Energia. This cost will be allowed within the Opex. The amount per customer is currently being reviewed by Gemserv as part of its CC&B upgrade review. Hence, the amount per customer, following its review, is likely to change. At this time and in the absence of more up to date information we have used the forecast costs as a placeholder, when the final licence modifications are published in June 2025, we will include an updated figure if available.

4.70 Within its response to the draft determination Power NI made no comment on the depreciation section.

5. Margin Review

Introduction to the margin review

5.1 Power NI must finance a range of fixed capital assets, working capital requirements and collateral requirements in order to finance the performance of its functions as a whole. As a service business, the company's fixed asset base, primarily consisting of investment in IT software and hardware is relatively small. Its overall capital requirement is instead dominated by day-to-day working capital needs and a range of collateral capital requirements necessary to engage in the energy market, purchase network services or provide collateral in respect of hedging contracts.

5.2 Specifically, as regards Power NI's relationships with counterparties, we observe that, in some cases, the company must either post cash as collateral or it can provide a letter of credit or other security such as a parent company guarantee in lieu of a cash posting. In other cases, the company does not post any collateral against potential future liabilities. In the draft determination, we made a distinction between actual cash injections funded by equity shareholder equity and other forms of 'contingent capital'. We have continued with this convention in this final determination.

5.3 In its Business Plan submission, the company estimated its capital requirement for the SPC25 Price Control period as £308m. The company estimated the cost of financing this capital as £33.6m per annum in nominal terms, calculated as shown in Table 5.1. In its response to the draft determination, the company provided a revised estimate for net margin of £29.6m per annum or 4.0% of forecast revenue.

	Capital (£m)	Finance rate	Margin £m
Equity	258	13.8%	35.7
Revolving credit facility	50	3.0%	1.5
Interest earned on deposits	(35)	5.2%	(1.8)
Required margin			35.3
Less amounts recovered through $\mathbf{G_t}$			(1.7)
Net margin to be recovered through $\mathbf{S_t}$			33.6
Forecast revenue			738.9
Net margin / forecast revenue			4.6%

Table 5.1: Power NI's business plan estimate of margin (£m nominal)

5.4 It is common practice to express the cost of financing electricity supply companies as a margin, described as a percentage of revenue. However, in the design of the price control licence conditions the margin is expressed as a monetary value which is then varied in line with inflation, the number of customers and the market price of energy as described in Chapter 3. In the previous price control, the margin was commonly referenced as 2.2%, although the actual percentage value varied as customer numbers varied, reducing as customer numbers decreased and increasing as customer numbers increased.

5.5 The level of margin proposed by the company, expressed as a percentage of turn-over would entail a significant increase in margin compared to the previous price control.

5.6 In its submissions, Power NI identified a number of reasons which it claimed to provide a justification for the increase. It argued that reform of the wholesale market through the introduction of I-SEM had increased its working capital and collateral requirements. It pointed to the cessation of the Power Procurement Business which had provided an implicit collateral and working capital offset to Power NI's retail operations. Power NI also suggested that its risk environment has increased due to a level of turbulence within the market and pointed to the recent exit of Electric Ireland from the domestic market. Power NI also argued that the previous methodology was not adequate to ensure its financeability.

5.7 In our draft determination we carefully considered Power NI's margin submission and engaged consultants (First Economics) to provide review, analysis and advice. At the time of the draft determination based on our analysis of the information provided by Power NI and the advice of our consultants, we proposed a margin of £15.9m per annum for the SPC25 Price Control (in nominal terms) which is equivalent to a margin of 2.2% of revenue. We also considered the impact which the forecast price of energy and forecast number of customers had on the calculation of margin, and we proposed to vary the margin to reflect differences between the actual values of these parameters and those used to forecast the net margin.

5.8 In this final determination, we have determined an average annual net margin over the duration of the price control of £16.5m per annum in nominal terms (£15.3m in October 2023 prices). This figure relates to the average number of consumers and average market price of energy (£150/MWh in nominal terms) assumed by Power NI in its Business Plan submission.

5.9 In presenting our assessment of the margin, we have followed the approach adopted by the company which determined the cost of capital required in nominal terms. In its submission, the company included an assessment of its capital requirement for a market price of energy of £100, £200, and £300 /MWh. Its proposed margin was based on a market price for energy of £150

MWh, applying the same nominal value in each year of the price control. However, the licence operates in real (October 2023) prices, applying CPIH as a general measure of inflation when determining tariffs in nominal terms. Having determined a margin in nominal terms, we set out in the draft determination how this would be converted to October 2023 prices for the purpose of the licence and how the scaling factors for market price of energy and customer numbers would be applied. We have maintained this approach for the final determination.

5.10 The material difference between the value of the margin requested by the company and the value of the margin in this final determination reflected, among other things, a difference of interpretation of UR's principal statutory objective and how this should be applied. We have described an explanation of the basis of our assessment in the section below, beginning at Paragraph 5.22. Before coming to that point, we have considered the response to the draft determination.

Responses to the draft determination.

5.11 CCNI agreed that Power NI's margin should be calculated for a regulated business rather than for a standalone company in a competitive marketplace. It noted that the analysis undertaken by First Economics for UR suggests that maintaining the profit margin at 2.2% allows headroom to manage changes in capital requirements or unforeseen changes of circumstances. CCNI therefore supported the proposed margin of 2.2%.

5.12 The difference between Power NI's assessment of margin and our draft determination of margin and the difference of interpretation underpinning our respective approaches to the determination of the margin, was a key focus of Power NI's response to the draft determination.

5.13 Power NI considered the level of margin allowed in the draft determination was inadequate. In summary, the company stated that "In its draft determination, the UR has failed to provide both an appropriate level, and appropriate structure, of margin for Power NI. As a result, it has failed to discharge both its principal duty to protect the interests of final customers and additionally its duty to ensure that Power NI as a regulated licensee can secure the necessary finance to fulfil its licensed obligations. This must be rectified for the final determination".

5.14 The company broke its arguments down into three broad themes:

a) UR does not recognise the inherent risk increase since the margin was last set in 2013. This is a broad argument which flows across a number of themes relating to the way in which we set the cost of equity, the recognition of capital, our decision to fund the company with regard to its current ownership, the level of mark-up applied to our determined margin to address peak to average capital requirements, and our decision to determine a margin on the basis of the individual circumstances of the relevant company taking account of the facts which UR is faced with at the time this decision falls to be made. Power NI's argued that the position taken by UR in the draft determination to be so implausible as to represent a clear error.

b) UR's approach did not properly recognise the element of Power NI's capital requirement that it accesses due to its position in Energia Group. Power NI argues that it should be regulated as a stand-alone entity without particular reference to the way it is currently financed. In practice, this relates to the level of contingent capital it is able to use which is part of an overall parent company facility. Power NI asserts that the allowance it has sought aligns with both UR's statutory duties, the Power NI Supply licence and reflects the return Energia Group could expect from placing its resources elsewhere (it's opportunity cost).

c) UR appears not to not have undertaken any financeability or scenario testing of the determined values. It characterised this as a significant omission. It suggested that financeability (including financial resilience) should typically be undertaken on a notional standalone company. Power NI claimed that, had UR carried out such a test, that process would have recognised the capital requirements a standalone company would have required.

UR's response to the consultation comments in respect of the margin

5.15 We note CCNI's support for the level of margin proposed in the draft determination.

5.16 The key themes raised by Power NI in its response were supported by more detailed commentary. We asked First Economics to consider and respond to the company's feedback. First Economics note on Power NI's Response to UR's SPC25 Draft Determination has been published with our final determination as Annex B. The note addresses the following contentions raised by Power NI in its response:

In respect of asset beta and risk

(i) UR's draft determination did not recognise the increase in risk that there has been since 2012/13 (pp.4, 22, 24-28 of Power NI's response).

(ii) The purported difference in risk/beta between NI and GB is implausible (pp.4, 22, 28-31)

(iii) The protection afforded by the G_t and K_t licence terms has only a "slight" effect on beta (pp.30, 32)

(iv) Experience during the energy price shock does not show that Power NI is insulated from wholesale price risk (pp.31-32)

(v) First Economics' identification/selection of an average beta is vague/unjustified (p.22)

In respect of Power NI's capital requirements.

(vi) UR was incorrect to state that, in some cases, Power NI's submitted forecasts of capital requirements were estimates of the capital that a standalone competitor would require rather than real-life requirements (p.18)

(vii) UR should have taken account of the capital that Power NI would require if it were a standalone supplier; failure do so represents a cross-subsidy from Energia (pp.5-6, 19-20)

(viii) First Economics mis-classified the capital that is needed to support hedging as 'contingent' capital (p.21-22)

(ix) The suggestion that Power NI should look to avoid posting cash collateral wherever possible is not in line with the practical reality of the market (pp.18-19)

(x) When sizing Power NI's capital requirement, UR focused too much on historical out-turns (p.18)

(xi) First Economics provided insufficient justification for its proposed £15m down-sizing of Power NI's submitted capital requirement (p.18)

(xii) The proposed downsizing of Power NI's working capital requirement is inconsistent with comments that UR made elsewhere in the draft determination (p.18)

(xiii) The margin needs to be sized at a level that supports worst-case rather than central-case capital requirements (p.18)

In respect of financeability.

(xiv) UR did not undertake a financeability test or run scenario tests. Had UR done so, it would have found that Power NI is not financeable (pp.7, 13-17, 40-41)

(xv) Fitch Ratings has said that they expect Power NI to earn a margin of 5% (p.16)

Other

(xvi) UR's departure from Power NI's £150/MWh power price means that UR is suggesting that Power NI should be "funded in hindsight" for any additional capital it needs during periods of high wholesale prices (pp. 17-18)

(xvii) UR should change and update its calculation of the risk-free rate (pp.32-34)

(xviii) UR should update its calculation of the TMR (pp.35-36)

(xix) Alternatives to CAPM point to a higher cost of equity (p.37)

(xx) First Economics' cross-checks on its margin calculation were unsound (pp.37-38)

(xxi) UR aimed up less than it did in 2013 (p.39)

5.17 Having considered and responded to the key points made by the company in response to the margin, our economic consultant continues to recommend that we make four corrections to the margin calculation submitted by Power NI:

a) Make a £15m downward adjustment to Power NI's forecasts of fixed assets, working capital and K correction. This adjustment was made in our draft determination and has been maintained in this final determination.

b) Treat the capital underpinning GB proxy hedges in the same way as contingent capital. This adjustment was made in our draft determination and has been maintained in this final determination.

c) Adjust Power NI's submitted cost of equity down to 10.5%, taking account of a revised value of the risk-free rate. Our draft determination was based on a cost of 10.2%. We have adopted the updated value of 10.5% for this final determination.

d) Cost all contingent or contingent-like forms of capital at 3%. This adjustment was made in our draft determination and is maintained for this final determination.

5.18 We have accepted the recommendations of our economic consultant and adjusted the calculation of margin accordingly. In addition, we have amended the interest rate applied to capital requirement related to over / under recoveries (the $\mathbf{KS_t}$ term) and cash collateral for the Single Electricity market (SEM) to 4.5%, consistent with the Bank of England base rate at the time of this final determination.

5.19 In its response to the draft determination, the company reiterated its view of the change of its risk between the last time the margin was reviewed in 2013 and this SPC25 Price Control. We have provided a response to the company's assessment beginning at Paragraph 5.63 below.

5.20 Our economic consultant's note on Power NI's Response to UR's SPC25 Draft Determination concludes that a capital base x cost of capital calculation, populated with the numbers provided by Power NI and the above corrections, points to a margin on turnover of 1.6%. However, First Economics continue to take the view that UR ought to provide some headroom above this figure to allow for the possibility that capital requirements could exceed the level identified by Power NI within year, between years or in the event of an unforeseen change of circumstances. Such 'headroom' would be consistent with the allowances that UR has made in previous supply price control reviews for a layer of standby risk capital and would ensure that Power NI is capable of remunerating investors ex-ante for making a long-term commitment to the business. In the draft determination, we allowed headroom in line with our economic consultant's recommendation. We have maintained this allowance for headroom in this final determination.

5.21 Our final determination continues to be based on the report and advice provided by First Economics in advance of the draft determination. For convenience, we have republished this report with the final determination as Annex A. This report included a recommendation that: in the event that there were to be a change in Power NI's ownership arrangements, resulting in a fundamental change in collateral costs or the imposition of new cash collateral requirements, we consider that there ought to be a process by which any unavoidable additional expense can be recovered once they are being incurred (e.g. through the $\mathbf{G_t}$ term). The existing $\mathbf{G_t}$ term allows for the recovery of defined cost items, including the costs of letters of credit, parent company guarantees and cash collateral. An estimate of this amount is deducted in the determination of margin and forecast / actual amounts included through the $\mathbf{G_t}$ term when tariffs are set. This mechanism makes provision for increases/reductions in the actual quantum of and type of capital required by the company, subject to it continuing to comply with its economic purchasing obligation. We have provided further detail on how this mechanism will function for SPC25 price control period in the section beginning at Paragraph 5.80 below.

Basis of our Final Determination of margin

5.22 In its submission on margin, the company set out its view of UR's statutory principal objective, quoting from Article 12 of the Energy Order with some emphasis added, as follows:

"To protect the interests of consumers of electricity supplied by authorised suppliers (wherever appropriate) by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity."

5.23 Having applied this emphasis to the wording of the Energy Order, the company restated UR's statutory principal objective as: "UR's principal objective is therefore to protect the interest of consumers by promoting effective competition." In restating our principal statutory objective, the company has chosen to remove the words "where appropriate" and then proceeded on the basis that these words have no effect.

5.24 It then concluded that: "Both the protection of customers – i.e., ensuring the margin is not set too high to the detriment of customers where Power NI has a dominant position in the marketplace – and the promotion of competition – i.e., ensuring the margin is not set too low to the detriment of competition, and of customers through the benefits that competition and competitive entry bring – are important."

5.25 In our view, there was no need to amend or restate UR's statutory principal objective, or to seek to emphasise some words in it above others.

5.26 Properly stated, UR's principal objective requires it to promote effective competition where UR deems this to be the appropriate mechanism to protect consumers. Competition is a means to an end and not an end in itself. The promotion of competition, however desirable, does not displace the overriding importance of consumer protection.

5.27 UR is committed to the promotion of a competitive supply market in NI. However, the suggestion that UR's statutory duties require Power NI to be permitted a higher margin – so as to, in effect, create greater headroom for new suppliers to enter the market and so facilitate market entry – is not consistent with UR's statutory duties as written. In effect it would privilege the promotion of competition (which is a means to an end) above the desired end of protecting the majority of consumers (among other things by keeping their electricity prices at a fair and reasonable level). This would be the opposite of the approach actually required by the duties. Whether and the extent to which measures should be taken to promote competition is a matter for UR's judgement as to what is appropriate to protect consumers. We are satisfied that the approach we have taken in this final determination is appropriate.

5.28 Applying its interpretation of our principal objective, the company has proposed a margin based the capital requirements that it believes a stand-alone company would face. The company does not explicitly define what it means by the term stand-alone company, but we infer the following from its approach:

a) That the company should be considered and financed as if it were a supply company which operated in a competitive market without the protections which regulation affords to Power NI.

b) That UR should determine the margin for Power NI on a purely notional company basis without reference to the individual circumstances of the company as it currently exists.

5.29 Having proposed its approach on a stand-alone company basis, the company provided estimates for a series of categories of working capital. In some cases, Power NI's forecasts are, very deliberately, not the capital requirements that the real-life Power NI business has or is likely to encounter but rather estimates of the capital that a hypothetical 'stand-alone' company would face if it were to take on Power NI's regulated customer book.

5.30 In calculating the cost of financing its capital requirement, the company assumed that a stand-alone company would only be able to finance 16% of its capital requirement through a revolving credit facility at a rate of 3%. It proposed that the remaining 84% of the stated capital requirement should be financed through a cost of capital (in practice a cost of equity) of 13.8%. This hypothetical approach bears no resemblance to the actual financing structure of the existing company.

5.31 The cost of equity proposed by the company was calculated to reflect the risk profile of a competitive company operating in the GB electricity supply market. While the company considered the protections afforded to its regulated business through a strong regulatory contract, it downplayed these, providing counter arguments. We did not consider these counter arguments compelling. For example:

a) The company highlights the risk that it might build up an excessive under-recovery (**KS_t**) which would increase future tariffs. It suggested that this created a risk that its customers would move to other suppliers. In response, we note that:

(i) The company is able to mitigate the build-up of a material under-recovery by seeking a tariff review.

(ii) If the under-recovery came from a loss of market share due to increased and more effective price competition, the company is able to respond by offering a tariff which is lower than the regulatory maximum, provided it can be competitive.

(iii) There is no evidence that this has been an issue in the past with market share both rising and falling at times without any apparent correlation to $\mathbf{KS_t}$.

(iv) There are also periods of over-recovery which results in the company offering a lower future tariff as the over-recovery is unwound. These periods offer the company an opportunity to gain market share.

b) The company also highlighted its position as Supplier of Last Resort (SOLR) and stated that its margin should be set at a level to ensure it can continue to robustly fulfil this retail market backstop related role. The company highlighted previous SOLR events which covered 1200 and 725 customers. It also highlighted the withdrawal of Electric Ireland from the Northern Ireland retail market as a further example, although this is an orderly withdrawal with a gradual transition of consumers to other companies. This risk should be set in the context of Power NI increasing its customer base by more than 2,500 per month in 2023 on average, planning for an increase of 3.6% per annum (>20k) during the SPC25 Price Control and continuing to actively promote its service to new consumers. In addition, our proposal to vary the margin in response to customer numbers will ensure the company receives adequate margin in respect of new customers as these events arise.

5.32 We understand the concept of a notional company and note that Ofgem, which regulates large numbers of similar companies across GB, routinely sets price controls on a notional company basis. However, UR has historically not sought to do this. Instead, we have set each price control on the basis of the individual circumstances of the relevant company. We have concluded that it is right to continue this consistent regulatory approach in this price control, taking account of the facts which UR is faced with at the time this decision falls to be made. These facts include the current structure of the Power NI business. We do not consider that it would be in the interest of consumers, and therefore not in line with our principal objective, to increase the margin of Power NI above that required by its existing structure in a way which would increase the potential profit of a dominant supplier which already benefits from its historical position as the incumbent supplier when supply competition was first introduced, its scale and a strong regulatory contract which makes for provision for full cost recovery of major elements of its costs.

5.33 The practical consequences of this approach are that:

a) We have taken account of the protections afforded to the company in its licence which allows it to recover significant parts of its cost base, including energy market costs, network costs and energy subsidy costs. As a result, we have determined a lower cost of equity than that proposed by the company to reflect the lower risk the company is exposed to compared to a supply company operating in the competitive GB market.

b) We have taken account of the circumstances of the company at the time this determination is made. In particular, we have taken account of the way in which the company is able to finance its current capital requirement using a higher proportion of contingent capital.

5.34 Applying this general approach and these principles, we determined a margin for the SPC25 period of £16.5m/a, compared to the revised margin of £29.6m proposed by the company in its response to the draft determination (both figures in nominal terms). This margin is based on a market cost of energy of £150 /MWh (constant in nominal) over the SPC25 period. It was also based on the company's estimate of the number of consumers over the SPC25 period. Given that the future market price of energy and the number of consumers served are both uncertain, we have included a mechanism which allows the actual margin recovered to flex as the market price of energy and the number of consumers change.

5.35 Our draft determination took account of the expert advice provided by First Economics. We had published that advice alongside our draft determination and have republished it again along with the final determination as Annex A. In the following sections of this Chapter, we provide a summary of our assessment of the company's submission and our determination of margin, taking account of the advice provided by First Economics. We also set out how we propose to apply the determined margin in the calculation of the $\mathbf{S}_t$ term, including how it would be varied to reflect the actual market price of energy and the actual number of consumers served.

Methodology

5.36 Power NI described its approach to assessing of margin for SPC25 as follows: “each element of capital committed to or available to the business is identified and an appropriate pricing applied based on an assessment of the appropriate capital structure and an estimate of the market pricing of that capital”.

5.37 As set out in our consultant’s report in Annex A, we agreed with the company on the broad methodological approach to the determination of margin as:

Profit in £m = capital base x percentage cost of capital.

5.38 The thinking behind this approach is that profit is first and foremost a return that can be distributed to investors, either in the form of fees and/or interest payments (in the case of debt obligations) or as potential dividends and/or capital appreciation (in the case of equity investments). To calibrate the appropriate amount of profit, it makes sense to think in terms of the percentage return on any debt that a company is taking and/or the percentage return on the equity capital that shareholders have agreed to put behind a firm.

5.39 This aligns with the way that investors view investments in companies. If the percentage return that is factored into the Power NI supply price controls is set so that it is in line with the risk-adjusted returns that are available elsewhere on other similar-looking investments (i.e. in line with the opportunity cost of capital), it ought to be that providers of capital will look favourably on the regulated supply businesses as investments and exhibit a willingness to supply the facilities and equity capital base that the businesses need in order to provide services to customers. We can also say that mistakenly setting returns above the opportunity cost of capital will result in customers paying more than they strictly need to. Conversely, if the returns on offer lie below the opportunity cost of capital, there is a danger that investor community might shun a supplier – i.e. a licensee will not be ‘financeable’ – thus presenting an avoidable risk to service.

5.40 In summary, our determination of margin must first assess the capital requirement and then determine the appropriate percentage cost of capital which must be applied to either the total capital requirement or to individual components of the capital requirement.

Capital Requirement

Power NI's assessment of capital requirement

5.41 Power NI developed a detailed bottom-up assessment of capital requirements for the four years of the SPC25 Price Control. This assessment was prepared:

a) for ten individual component of capital requirements summed to an overall capital requirement;

b) on the basis of nominal costs allowing for inflation;

c) on a monthly basis, allowing annual averages and annual peak month values to be calculated;

d) including projections of customer numbers and average energy consumption per household; and

e) with separate assessments for three scenarios based on different market cost of energy of £100, £200, and £300 /MWh, in the company's analysis, the cost of energy for each scenario was held constant in nominal terms in each year, declining in real terms.

5.42 The company assessment of margin for SPC25 was based on a capital requirement of £308m being:

a) the average of the annual average capital requirement for each year of SPC25; and,

b) the average of the scenarios for the market cost of energy of £100 and £200 /MWh, effectively a market cost of energy of £150/MWh.

5.43 The average annual capital requirement calculated by the company for each of its energy price scenarios is shown in Table 5.2 below.

Market price of energy	FY26	FY27	FY28	FY29	Average
£100/MWh	205	219	230	248	226
£200/MWh	353	379	400	428	390
£300/MWh	481	519	549	587	534
Power NI assessment at150/MWh	279	299	315	338	308

Table 5.2 Power NI's assessment of average capital requirement (£m nominal)

5.44 Underpinning these average values is the company's assessment of monthly values which show an annual pattern with the peak values occurring in the winter. This assessment is reproduced in Figure 5-1 below.

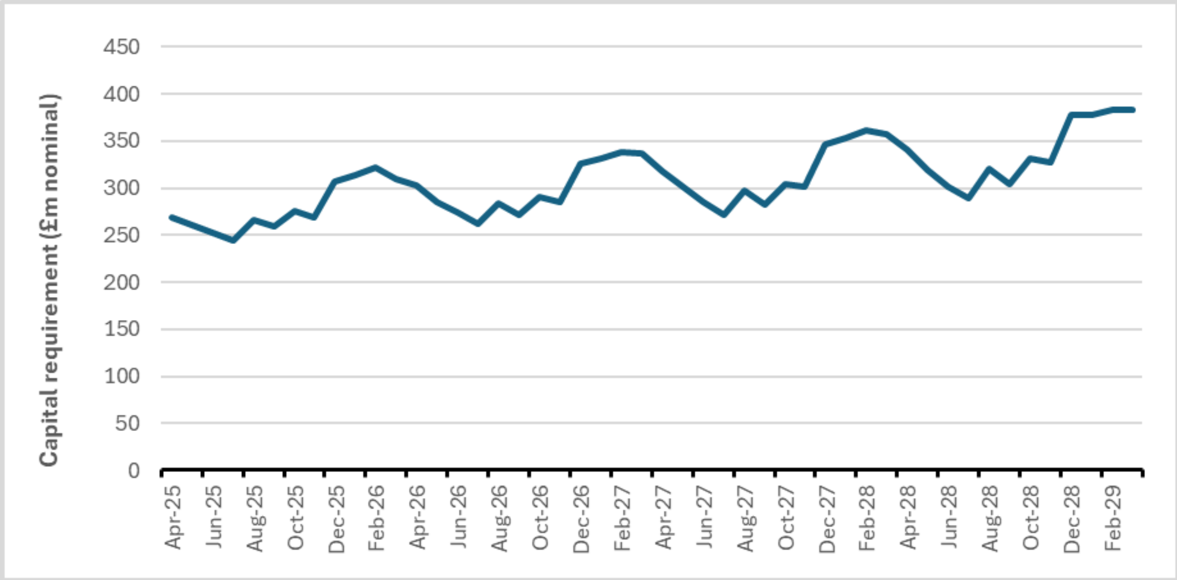

Figure 5-1: Power NI's assessment of monthly capital requirement over SPC25

5.45 The company's assessment shows a gradual upward trend in working capital over time underpinned by growth in customer numbers, growth in consumption per customer and inflation. The difference in annual average and annual peak month is circa 14%.

5.46 The company's assessment of average capital requirement also shows a strong dependency on the market price of energy, reflecting the impact that this has on collateral and security deposits the company has to make to purchase energy from the Single Electricity Market (SEM) and when it hedges forward energy prices.

5.47 The variation of capital requirement with market price of energy is shown in Figure 5.2. While not a strict linear relationship, it shows a strong linear trend with an approximate fixed value of £76m and a variable element of £1.54m of working capital for every £1/MWh increase in the market price of energy. It reinforces the fact that the market price of energy is a key determinant for the capital requirement.

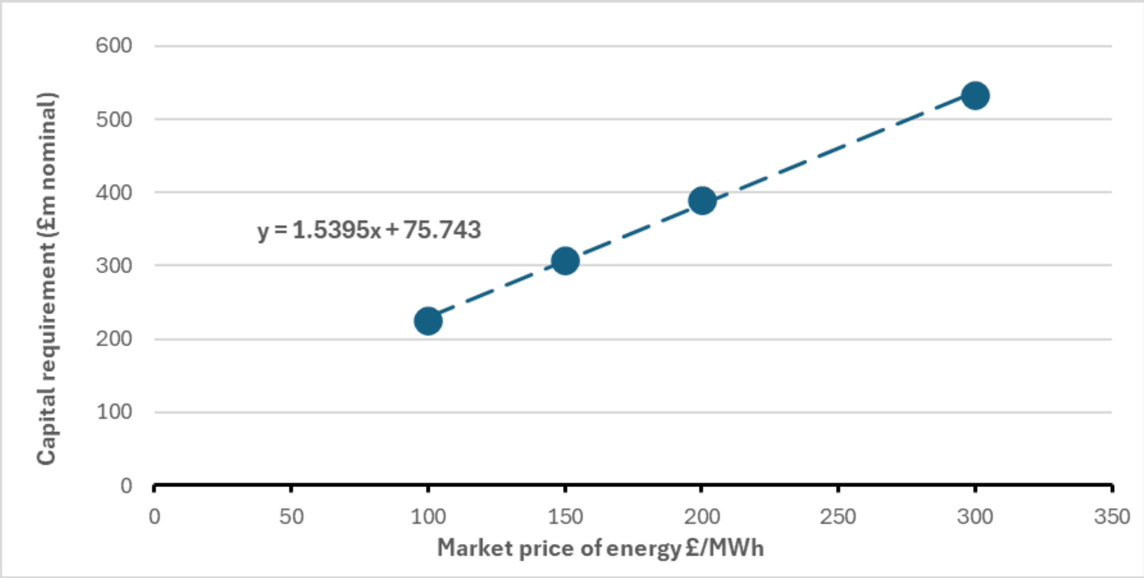

Figure 5.2: Variation of working capital with the market price of energy

5.48 The company's assessment of its capital requirement is built up of detailed assessments of 10 components covering:

a) Fixed assets: where the company has invested in premises, office equipment, IT software and hardware and other capital assets to deliver its service.

b) Working capital: dominated by payments for energy and network services paid in advance of collecting revenue from consumers.

c) Collateral and security deposits: Power NI must post cash or collateral for the purchase of energy in the SEM and in anticipation of the network charges it will incur. It might be required to post collateral in respect of hedging contracts it enters into in respect of future energy costs or foreign exchange rates.

d) Stand-by capital: it may also be appropriate for a supply company to have an amount of cash on standby to deal with unforeseeable day-to-day deviations to cash flow.

5.49 A breakdown of Power NI's assessment of capital requirements by component is reproduced in Table 5.3

	Category	Capital Requirement (£m)	Capital Requirement (% of total)	Current means of financing
1	Net Working Capital	31	10%	Equity
2	Intra-Month	8	3%	Equity
3	K-Correction	27	9%	Equity
4	Prefunding	6	2%	Equity
5	NIE Networks & SONI	18	6%	Contingent
6	SEMO & NEMO	32	11%	25% Equity, 75% contingent
7	CFDs	37	12%	25% Equity, 75% contingent
8	GB Power	112	36%	None
9	FX	24	8%	Parent company guarantee
10	Fixed Assets	13	4%	Equity
		308		

Table 5.3: Power NI's assessment of capital requirement by component (£m nominal)

5.50 We asked the company to provide information on how each component of its capital requirement is currently financed and have included this information in Table 5.3. Based on the information provided by the company, it currently finances as equity (cash) 33%, 23% by contingent capital (letters of credit) with 44% supported by an actual or implied parent company guarantee. This compares to the company's assessment of margin for SPC25 where it assumes that 84% of its working capital should be financed by consumers as equity. This difference is critical to the difference between how the company and UR have approached the determination of margin in principle as described in the section above beginning at Paragraph 5.22.

UR's determination of capital requirement

5.51 We agree with the categories of capital the company has considered in its assessment. We note the assessment prepared by our economic consultant on capital requirement and the recommendation that the overall capital requirement proposed by the company should be reduced by £15m. We have set out our views on the assessment of each category of capital requirement below. But first we have reviewed the company's assumptions on inflation, customer growth, consumption growth and market cost of energy which are key common drivers in its projection of capital requirement.

5.52 The company has calculated capital requirement in SPC25 assuming the level of inflation set out in Table 5.4. We consider these assumptions reasonable, but that they do not apply to the cost of energy in the assessment of working capital which has been set as a constant in each year. We have taken account of this when determining a margin on October 2023 prices for the purpose of the licence and when determining scaling factors in respect of customer numbers and market price of energy which are applied to the determined value of margin in the licence when determining the maximum regulated tariff.

	FY25	FY26	FY27	FY28	FY29
Annual inflation	3.00%	2.00%	2.00%	2.00%	2.00%

Table 5.4:Power NI's assumption for inflation in SPC25

5.53 The company's assessment of capital requirement assumes the rate of growth in customer numbers over SPC25 set out in Table 5.5. This forecast is underpinned by an assumed addition of circa 20,000 customers per annum. This assumption of sustained growth comes after a six-year period when customer numbers increased by 10% in total, mainly driven by growth of 7% in FY24 largely due to customers moving from Electric Ireland to Power NI. The assumption that consumer numbers will increase by 20% in the next five years (taking Power NI market share to circa 70%) seems optimistic when most recent customer data suggests that annual growth has fallen to 2.4%. However, we have used the Power NI figures in our determination but continue to vary margin allowed in the maximum regulated tariff in proportion to consumer numbers.

	FY25	FY26	FY27	FY28	FY29
Growth in consumers	3.9%	3.7%	3.7%	3.6%	3.5%

Table 5.5: Power NI's projection of consumer numbers in SPC25

5.54 The company's assessment of capital requirement assumes the consumption per consumer will grow in SPC25 as shown in Table 5.6. The company's assessment is based on the Generation Capacity Statement (GCS) with an average growth rate of more than 4% per annum for domestic properties as low carbon technologies such as electric cars and heat pumps are connected. This rate of growth did not materialise in FY24 when consumption per customer fell slightly. However, the company has assumed that the GCS projections will be maintained, resulting in an increased percentage uplift in FY25. In our final determination for NIE Network's RP7 we highlighted the risk that the rate of connection of LCT technology might lag behind targets and that this would increase tariffs for all consumers in the short term. In the case of Power NI, its latest tariff covers the period from December 2024 to November 2026 (most of the first two years of SPC25), the forecast total meter point sales were more than 10% lower than the company's forecasts for the same period in SPC25. There is a risk that the consumption figures used by the company to determine margin for SPC25 are at the upper end of expectations. Based on the trend presented in Figure 5.2, if consumption over the SPC25 period was 10% lower than projected, capital requirement would reduce by circa £20m.

	FY25	FY26	FY27	FY28	FY29
Average consumption kWh/customer	3369	3508	3651	3796	3932
Growth in consumption	9.6%	4.1%	4.1%	4.0%	3.6%

Table 5.6: Power NI's projection of consumption per consumer in SCP25

5.55 The company's assessment of working capital is based on a market price for energy of £150 /MWh over the SPC25 period.

5.56 In recent years there has been a significant peak in electricity prices as shown in the SEM Day Ahead Market (DAM) prices on Figure 5.3 as gas prices increased as a result of the economy recovery following Covid19 and the war in the Ukraine. While some stability has returned to markets, market prices for electricity have settled at about £100/ MWh compared to £50 or less before 2021. The recent Power NI tariff review for the period from December 2024 to November 2026 (including much of the first half of the SPC25 Price Control period), was based on a market price of energy of £100/MWh, reflecting market information on forward prices for electricity. On the basis of current and forward prices for electricity, using a market price of electricity of £150/MWh would appear to provide some headroom in a forward-looking determination of margin. However, it is a matter of fact that this price was exceeded 25% of the time in the SEM DAM (on a 12-month rolling average basis) since October 2018. While the lesson of the recent past is that we must be cautious about projecting economic conditions from current conditions, it is also true that the recent spikes in energy prices were driven by extreme events, and we should not assume that they are a guide to the future. Therefore, we have concluded that a market price of energy of £150/MWh is a conservative basis for determining a forward-looking margin which, on the basis of current forward prices for energy, includes headroom. We have assessed the company's proposed capital requirement on this basis.

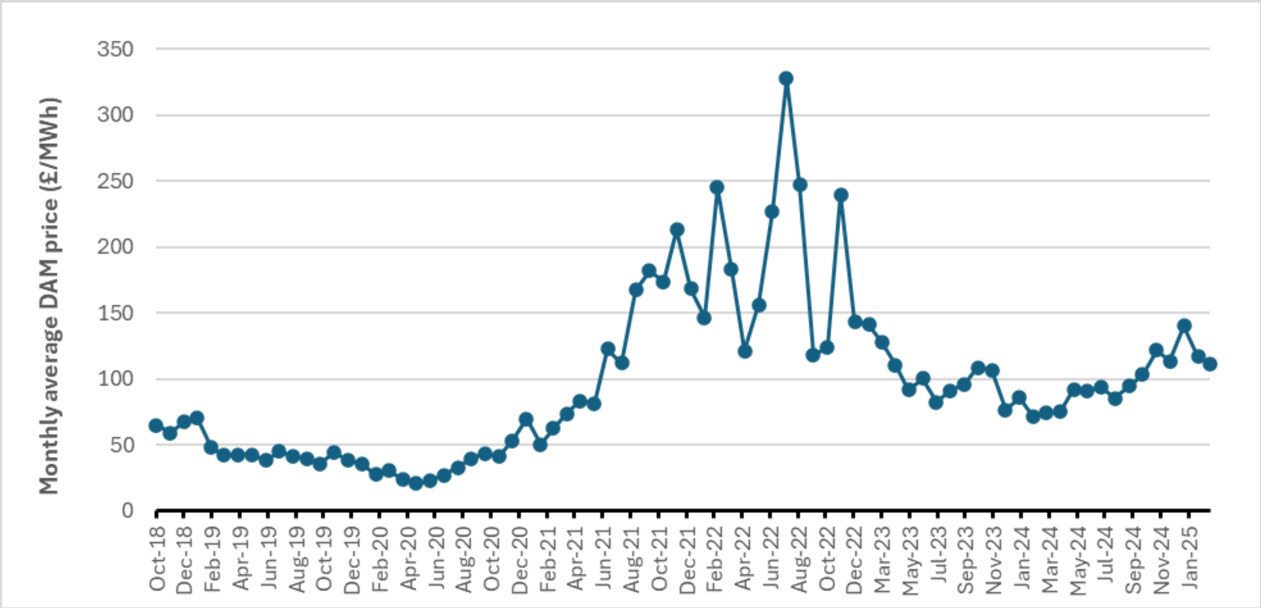

Figure 5.3: Monthly average SEM Day Ahead Market prices (£/MWh)

5.57 The company's assessment of working capital for the SPC25 Price Control period is summarised in Table 5.3. Our economic consultant's assessment of the individual categories is set out in Annex A, including a recommendation that the total quantum of working capital should be reduced by £15m for the purpose of determining the margin. With regard to each of the key factors identified by Power NI:

a) **Net Working Capital**: Power NI's forecast of net working capital is based on very cyclical positive values compared to recent historical values which have been negative, subject to a limited number of positive values in 2022. The company has added an amount of circa £5m against a risk that debtor days will increase without providing an explanation of why this is justified. Taking account of the comparison of historical data and forecast of net working capital and the extra allowance for increased debtor days, the company's assessment of an average capital requirement of £31m appears conservative.

b) **Intra-Month**: Power NI has identified an additional capital requirement to cover the peak day in month. We have accepted this assessment.

c) **K-Correction**: The method by which the company's tariff is set exposes it to over and under-recovery of costs. These over / under recoveries of costs are recovered in future tariffs. However, in the event of an under-recovery, the company must finance the cash flow until it transfers forward into tariffs. Power NI undertook an analysis of future K factor values which suggested that it would be required to finance an average value of £12m over the SPC25 Price Control period. This forecast was more peaky than historical values and mainly generated only positive values when the past has included over and under recovery. For the purpose of establishing a capital requirement, the company increased its bottom-up value by a further £15m. In support of this it provided information on monthly K factor which looked back at the peak K factor by quarter from 2020. This showed that the peak under-recovery exceeded £20m in 8% of quarters, with a peak under-recovery of just over £30m. However, we are concerned that the company is, in this case considering historical peaks when in other areas it uses bottom-up assessments based on short term peaks. In view of the bottom-up assessment provided and the historical values, a value in the range £12m to £20m would appear to be a conservative estimate compared to the £27m average proposed by the company.

d) **Prefunding**: Power NI has identified an additional capital requirement necessary to ensure that cash is available in its bank accounts to cover clear payments when they arise. We have accepted this assessment.

e) **NIE Networks & SONI**: Power NI must post collateral with NIE Networks and SONI in advance of using both network and system services. Considering, the current levels of expenditure, expected increases in network charges as a result of the RP7 Final Determination and recent increases in system service charges, the company's forecast of capital requirement appears to be reasonable.

f) **SEMO & NEMO**: Power NI must post collateral in the energy market in advance of trading. Considering the relationship between these collateral requirements and the market price of energy reflected in historical collateral requirements, the company's assessment of working capital for this component at a market price for energy of £150/MWh is reasonable.

g) **CfDs (energy price hedges)**: The company hedges its forward price of energy through Contracts for Difference with SEM market generators. The actual level of working capital requirement at any point in time will depend on the price of power relative to the hedged price. However, Power NI's forecasts are at and above the recent peak in the historical level of collateral posed.

h) **GB Power (energy price hedges)**: Power NI enters into energy price hedges in GB markets as proxy hedge where there is insufficient capacity for the market in hedging contracts in SEM. It does not make collateral payments on these contracts and has constructed a capital requirement on a similar basis to the CfD hedging contracts.

i) **Foreign Exchange (FX hedges)**: Power NI has set out potential collateral requirements for FX hedges for payments and hedges denominated in euros. The potential collateral is dominated by forward hedges for energy which make up 80% of the average hedged values. This is assumed to be hedged on a rolling basis at a relative constant amount increasing with consumption. The remainder of the FX hedge is in respect of SEM market charges denominated in euros. Tariffs are set at the start of each year and the amount hedged declines over the year. The overall profile of future capital requirement for FX hedging is more level than the historical capital requirement of FX hedges, suggesting a marked shift in forecast approach compared to historical approach. Had the forecast profile reflected the historical profile the average FX capital requirement would have been lower by circa 30%.

j) **Fixed Assets**: The company has assumed that fixed assets would increase in the last 18 months of the SPC25 Price Control period due to additional expenditure on smart metering and the introduction of a new customer contact and billing system. We plan to address these through the $\mathbf{E}_t$ mechanisms once the costs are known. The company is currently in the process of replacing its customer contact and billing system and the final costs are not yet known. We note that the company's approach to including fixed asset value in the capital requirement underpinning the margin will require careful consideration of depreciation of $\mathbf{E}_t$ terms to ensure that the calculation of depreciation and any allowance for return is consistent with their treatment in the calculation of margin.

5.58 Our review of the components of working capital confirms the view of our economic consultant that "it would not be unreasonable to mark down Power NI's forecast capital requirements in the areas we have highlighted by around £10-20m". For the purpose of calculating margin, we have marked down the submitted capital base by £15m as shown in Paragraph 5.57.

Cost of capital

5.59 When calculating the cost of financing the capital requirement we have to consider reasonable rates for:

a) Equity.

b) Contingent capital.

c) Interest on various deposits.

d) Allowance for the ability for the company to recover part of its cost of financing through the $\mathbf{G_t}$ term.

Cost of capital (equity)

5.60 In calculating the allowed cost of equity, UR, like most economic regulators, uses the Capital Asset Pricing Model (CAPM) to determine the returns that shareholders require in exchange for their equity investments. CAPM estimates the required return to be a function of the risk-free rate (Rf), the expected return on the market portfolio (Rm) and a firm-specific measure of risk (the equity beta (ße) as follows:

$$Ke = Rf + \beta e * (Rm - Rf)$$

5.61 This is the same approach adopted by the company. The key parameters used in our assessment are set out in Table 5.7 where they are compared to the revised parameters proposed by the company in its response to the draft determination.

Parameter	Power NI	UR
Expected market return	9.1%	8.9%
Risk-free rate	5.1%	4.7%
Asset beta	1.0	0.75
Cost of equity	9.1%	7.9%
Tax rate	25%	25%
Pre-tax cost of equity	**12.2%**	**10.5%**

Table 5.7: Cost of equity proposals for SPC25

5.62 The proposed cost of equity is based on the advice of our consultant as set out in Annex A, noting:

a) We agree with the company that the cost of capital of cash investments and collateral posting should be calculated as equity only (gearing = 0%).

b) We had adopted a value for expected market returns in real terms of 6.75%, consistent with our recent determination for NIE Networks (RP7), compared to the value of 6.65% proposed by the company. In the past, regulators have commonly used a value of 6.5%. We adopted a slightly higher value in RP7, noting the move to higher real rates of interest and Ofgem and Ofwat’s indications that they would consider ranges with higher upper values for their next round of network price controls. To covert this to a nominal value, we adjusted for CPIH inflation of 2%, being the value projected by OBR at the end of its latest forecasts.

c) We adopted a risk-free rate of 4.7%, based on data as of March 2025. This is based on a basket of index linked gilts and two types of AAA non-government bonds weighted at 50:25:25. The value has been updated to reflect current market values in advance of the final determination.

d) We adopted an asset beta of 0.75 as recommended by our consultants compared to a revised figure of 0.85 to 1.00 proposed by Power NI in response to the draft determination. This is an increase from the value of 0.6 used in previous supply price controls. The company's position in its business plan submission was that we should adopt an asset beta of 1.10, consistent with that used by Ofgem when determining price caps for GB supply companies. However, we note the strong regulatory protections available to Power NI which include mechanisms to recover its energy costs and a range of network, market and energy incentive costs. We therefore disagree with Power NI's premise that it has a similar risk profile to GB supply companies operating in a commercial / competitive environment where the experience of company failure in recent times reveals a higher risk. We note that an asset beta of 0.7 to 0.8 is consistent with the average equity beta of 1.0 after accounting for the average level of gearing exhibited by UK listed firms.

e) The data above is the basis for a post-tax cost of equity. We have adjusted this to a pre-tax cost of equity by allowing for corporation tax at 25%.

Asset Beta

5.63 In its response to the draft determination Power NI argued that the relative risk analysis provided as part of its business plan submission suggested strongly that:

a) The changes in the Northern Ireland market since the 0.6 beta was set in 2013 support an asset beta above 0.75

b) The relative risk between the GB market and the Northern Ireland market supports an asset beta above 0.75

c) The changes in risk since 2013 in the Northern Ireland market are greater than the differences between the NI and GB markets and therefore the change in beta since 2013 should be greater than any difference in beta between the GB and NI markets, which suggests the asset beta should be, as a minimum, greater than 0.85.

5.64 Power NI also highlighted its view that UR had not recognised arguments put forward by Power NI in relation to the risks it faces, and that UR did not carry out a detailed assessment and consideration of the relative risks its faces both in Northern Ireland relative to 2013 and relative to GB in 2024.

5.65 We note that Power NI revised its estimate of asset beta from an initial range of 1.0 to 1.2 (settling on a mid-point 1.10) in its business plan submission to a range of 0.85 and 1.0 in its response to the draft determination (settling on the upper end of that range).

UR response on risk and asset beta

5.66 In relation to Power NI's view that UR had not recognised arguments put forward by it in relation to the risk it faces relative in Northern Ireland to 2013 and relative to GB in 2024, we are satisfied that these issues were appropriately dealt with in the draft determination. While we do not disagree that some of the background factors suggest that there is greater volatility and risk in the market than existed previously, these factors only generate enhanced risk for Power NI itself to the extent that it is not immunised or at least substantially protected from their effects via the price control or other aspects of the regulatory regime. In adopting a point estimate for the asset beta, we are concerned not with the risks in the market as a whole, but only those to which Power NI is subject. In our view, Power NI is well shielded from these risks by the protections built into its price control both historically and for SPC25.

5.67 As Annex B of this final determination notes Power NI's response to the draft determination which compares risks now to risks in 2013 makes no reference to the protection that the regulatory arrangements in Power NI's licence - particularly the design of the $\mathbf{G_t}$ term in the price control - both have in the past afforded, and will continue to afford under SPC25, in relation to the recovery of Power NI's electricity purchase costs. We consider that this is a significant flaw in its case for a higher asset beta than UR has determined.

5.68 With regard to the relative risks which Power NI argues that it faces compared to GB, in Annex B of this final determination our economic consultant observes that it is clear that the cost-recovery risks that the GB suppliers have faced under Ofgem's energy price cap design are of a different order of magnitude to any risks that exist under UR's regulatory framework.

5.69 Power NI also, in its response to the draft determination, expressed the view that while in theory GB suppliers are exposed to more wholesale price risk, this is mitigated in practice to some extent by the quarterly updates to the default tariffs and the inclusion of a headroom allowance in setting tariffs.

5.70 The company highlighted that while costs associated with these risks (excluding bad debt) should ultimately be recovered, they do present significant liquidity risks and recovery is not guaranteed. It also said that while it has always accepted that the K correction mechanism provides a degree of risk protection, it is not an absolute protection especially in the light of UR's insistence on a longer recovery period than Power NI is comfortable with.

5.71 Ultimately, having taken all of these submissions into account, we are satisfied that both the $\mathbf{G_t}$ and $\mathbf{KS_t}$ terms provide Power NI with very substantial protection against risks that is not available to suppliers in GB. While we can never exclude the remote possibility of Power NI building up a significant under recovery, we note this is further mitigated by:

- Power NI's ability to amend tariffs to prevent a material build-up of under-recoveries.
- The symmetrical nature of the effect. An over-recovery of revenue will lower future tariffs, giving Power NI a potential competitive advantage which would allow it to regain consumers.
- The absence of any evidence of a historic rapid downward movement in Power NI customer numbers (on the contrary, they have increased in recent times).
- The absence of any evidence of a historic under recovery of the type to which Power NI refers (so that the risk appears largely conceptual and theoretical, rather than anything which can be observed even in the relative period of market volatility which has existed in the recent past).

Contingent capital

5.72 Power NI proposed a rate of 3% for contingent capital applied to the £50m revolving credit facility included in its assessment of margin on a stand-alone company basis. Our consultant considered a range of precedents on the cost of contingent capital and noted that the evidence clearly pointed to a range between 2% and 3% and used a value of 3% at the upper end of this range to estimate a margin for Power NI. We have adopted this approach in our determination, recognising the risk that Power NI carries in financing its activities.

5.73 In line with the recommendations given by our consultant, we have also applied this rate for estimated capital requirements where Power NI does not post collateral at present. This approach provides for any implicit cross subsidy that Power NI receives from its parent company that relieves it of obligations that it might otherwise face as a stand-alone entity in respect of counterparties.

Interest on various deposits

5.74 We have allowed for interest on our revised estimates of the capital requirement for K-factor and SEMO & NEMO cash amounts. We have used the revised interest rate of 4.5% proposed by the company which is consistent with Bank of England Base rates at the time of the final determination. We have adjusted the amounts this applied to reflect the amendments we made to the capital requirement.

Allowance for the ability for the company to recover part of its cost of financing through the G_t term.

5.75 The company is able to recover actual costs of letters of credit through the $\mathbf{G_t}$ term of the licence. We have used the company's estimate of £1.7m for this adjustment.

Determination of margin

5.76 Following the approach outlined above, we have prepared a bottom-up estimate of margin of £12.2m, equivalent to 1.7% of revenue. This takes account of:

a) Our decision to reduce the capital requirement by £15m with the adjustments made to components where equity is required.

b) The application of a cost of equity of 10.5%.

c) A cost of contingent capital of 3.0%

d) The allocation of capital requirement between cash (equity) and contingent capital in the same way as the company currently finances these activities.

e) The application of the contingent capital rate to estimated working capital where the company does not currently post any collateral in lieu of any real or implied company or parent company guarantee.

f) The deduction of deposit for the amount of K-factor and SEMO and NEMO cash collateral at revised interest rate of 4.5%.

g) The deduction of actual costs of collateral which the company can recover through the $\mathbf{G_t}$ term based on the company's estimate of a current value.

5.77 Our bottom-up calculation of margin is presented in Table 5.8 below.

Capital Requirement	Capital (£m)	Funding	Allocation (%)	Allocation (£m	Rate	Margin
Net working capital	22.5	WACC	100%	22.5	10.50%	2.4
Intra-Month	8.1	WACC	100%	8.1	10.50%	0.8
K-Correction	23.9	WACC	100%	23.9	10.50%	2.5
Prefunding	5.9	WACC	100%	5.9	10.50%	0.6
NIE Networks & SONI	17.7	Contingent	100%	17.7	3.00%	0.5
SEMO & NEMO	32.5	WACC	25%	8.1	10.50%	0.9
		Contingent	75%	24.4	3.00%	0.7
CFDs (energy hedges)	37.2	WACC	25%	9.3	10.50%	1.0
		Contingent	75%	27.9	3.00%	0.8
GB Power (energy hedges)	111.5	Contingent	100%	111.5	3.00%	3.3
FX	23.7	Contingent	100%	23.7	3.00%	0.7
Fixed Assets	10	WACC	100%	9.9	10.50%	1.0
Total				292.8		15.4
Less interest on deposit (K-factor and NEMO/SEMO) equity				32.0	4.5%	(1.4)
Less amount recovered through $\mathbf{G_t}$						(1.7)
Net margin to be recovered through $\mathbf{S_t}$						12.2

Table 5.8: UR proposed margin (nominal prices)

5.78 Our bottom-up assessment of margin to be recovered through $\mathbf{S_t}$ is the equivalent of 1.7% of revenue. At the draft determination, our consultant recommended that UR should provide some headroom above this figure, suggesting that we do not reduce the margin below the current margin rate of 2.2%. This approach is consistent with the principle UR has applied in previous supply price control reviews for a layer of standby risk capital that would ensure that Power NI is capable of remunerating investors ex-ante for making long term commitments to the business. It makes provision for the possibility that capital requirements will exceed the level identified by Power NI within year, between years or in the event of unforeseen changes in circumstances including changes in the way that different components of the capital requirement must be financed.

5.79 For the final determination, we have decided to apply the same percentage uplift to the margin as was applied for the draft determination (35.2%), with a final determined margin for the price control of £16.5m at mid-price control prices.

Recovery of actual cost of collateral through the G_t term

5.80 In the most recent price control, an amount was deducted from the determined margin which represented the actual cost of credit facilities required to provide collateral necessary to purchase energy and other products required to provide energy to domestic consumers. When tariffs are determined, this deduction is replaced by the actual cost of this type of credit, first as a forecast and then as actual historical values become available. The difference between the forecast and actual amounts is continuously corrected through the $\mathbf{KS_t}$ term of the licence of over / under recovery of revenue.

5.81 This has the advantage of reducing the risk to consumer and company in respect of movements in the actual cost of collateral requirements necessary to purchase and supply energy.

5.82 In its review of Power NI's response to the SCP25 Draft Determination, our economic consultant stated that:

"In the event that Power NI's circumstances were to change, due to a change of ownership or any other reason, and the business were to face a different market reality, we have suggested that the UR should provide scope for Power NI to make a claim for the costs of any additional collateral that it may have to post under the $\mathbf{G_t}$ term. We continue to consider that this is the best way of dealing with possible alternative states of the world that Power NI may or may not encounter."

5.83 The deduction of a pre-estimate of various collateral costs from the determined margin and the inclusion of an amount for actual collateral costs when tariffs are set, addresses this point. It allows for changes in the total quantum of collateral, change in quantum of individual types of collateral and changes in the actual cost of collateral which might change over time.

5.84 Therefore, we propose to continue the mechanism for adjusting for actual costs of collateral through the $\mathbf{G_t}$ term established in the last price control. In the determination of margin above, we have deducted an amount of £1.7m which reflects a pre-estimate of the actual cost of credit to fund collateral requirements of energy markets, network costs, energy price hedging, and foreign exchange costs. When tariffs are set, an amount is included to reflect the forecast and, eventually, actual costs of funding this collateral.

5.85 To ensure that this mechanism is effective and to provide clarity on how it will operate in the SPC25 Price Control Period, we must:

- define the scope of the mechanism;

- define how amounts relating to different types of collateral will be calculated in practice;

- ensure that the deduction from the determined margin in this final determination is consistent with the approach we intend to use to calculate the $\mathbf{G_t}$ cost of credit amount in practice;

- ensure that the method for calculating future amounts is consistent with the determination of margin in this final determination; and,

- modify the licence to formalise the use of this mechanism in the determination of the maximum average maximum tariff.

5.86 **Scope of the mechanism.** The cost of credit covered in this mechanism is the cost of letters of credit, parent company guarantees, and cash posted as collateral necessary to purchase energy and other products required to provide energy to domestic consumers. To ensure consistency with the final determination, this does not include any parent company guarantees posted against GB hedges which have been valued in the margin as an implied parent company guarantee although no guarantees have been posted. As a result, this item was not included in the pre-estimate of the cost of credit amount in the final determination.

5.87 The scope of collateral necessary to purchase energy and other products required to provide energy to domestic consumers will include:

- collateral posted in the Single Electricity Markets (SEMO and NEMO);

- collateral posted with network operators (SONI and NIE Networks);

- collateral posted with hedging products, contracts for difference or other products used to hedge the forward price of energy in line with the economic purchasing obligation of the licence; and,

- collateral posted for foreign exchange hedges or similar products used to hedge collateral posted in for the items described above which are paid for in euros against the forward euro GB£ exchange rate.

5.88 The scope of collateral necessary to purchase energy and other products required to provide energy to domestic consumers will exclude costs of financing other activities including the $\mathbf{KS_t}$ (over / under recovery term), fixed assets, net working capital, intra-month capital, and pre-funding lines of the overall capital requirements for which a cost of equity has been allowed in the final determination.

5.89 **Treatment of amounts relating to letters of credit.** The value of letters of credit will be calculated in two parts: an amount in respect of the letters of credit used; and an amount in respect of letters of credit made available but not utilised.

5.90 The amount for letters of credit utilised shall be

- The actual average amount of letters of credit posted by the licensee or any parent or related company on behalf of the licensee in the relevant year.

  multiplied by

- The actual average cost of letters of credit posted by the licensee or any parent or related company on behalf of the licensee in the relevant year.

5.91 The amount for letters of credit available but not utilised shall be:

- The difference in a reasonable amount of letter of credit facilities secured by the licensee or made available by any parent or related company on behalf of the licensee in the relevant year, less the amount of letters of credit utilised.

  multiplied by

- The actual average availability fee for letters of credit facilities secured by the licensee or made available by any parent or related company on behalf of the licensee in the relevant year, but not utilised.

5.92 Treatment of amounts relating to parent company guarantees. The amount for parent company guarantees shall be:

- The actual average amount of parent company guarantees posted by the licensee or any parent or related company on behalf of the licensee in the relevant year, excluding any parent company guarantees posted in respect of GB hedges.

  multiplied by

- The actual average cost of letters of credit utilised by the licensee or any parent or related company on behalf of the licensee in the relevant year.

5.93 Treatment of amounts relating to cash collateral. The value of cash collateral shall be:

- The total amount of cash collateral posted by the licensee which is greater than the amount of cash collateral assumed in the final determination of margin (£15.3 m in October 2023 prices).

  multiplied by

- the interest rate paid by the licensee or any parent or related company providing cash to the licensee in the relevant year, or failing a clear line of sight to the cost of cash collateral, the specified average rate plus 2%.

5.94 **Consistency with the margin calculation deduction in the licence.** We have reviewed the deduction from the determined margin in this final determination are satisfied that it is consistent with the methodology set out above. In particular:

- There is no deduction for cash collateral.

- There is no deduction in respect of GB hedges.

5.95 **Consistency with the determined margin.** We consider that the method for calculating future amounts is consistent with the determination of margin in this final determination. In particular, it does not allow recovery of costs against cash collateral posting until the amount of collateral posted exceeds that amount of collateral priced at a full cost of equity in the determined margin.

Licence modifications. We propose to modify the licence to give effect to the methodology for determining the actual cost of credit recovered by amending the definition of the $\mathbf{G_t}$ term of the licence to include the recovery of a cost of credit amount. This will be done by adding an additional sub-paragraph to the definition of the $\mathbf{G_t}$ terms which facilitates recovery of

“an amount equal to that approved by the Authority, in accordance with the principles set out in a methodology entitled “Power NI Supply Price Control G_t Cost of Credit Mechanism” published on the 30 June 2025[19], as representing the deemed costs of credit cover in relevant year t that would not otherwise be recoverable by the Licensee under any other provision of this Annex 2.”

5.96 This section of the final determination provides a draft of that methodology. We are consulting on this draft methodology with Power NI, and other

[19] Being the date on which we intend to publish our decision on licence modifications.

interested parties generally as an associated part of the consultation on licence modifications under Article 14 of the Electricity Order. As we made clear earlier in this final determination, the purpose of these changes is to codify historic practice for the purposes of transparency, rather than to change the way in which the $\mathbf{G_t}$ term operates in practice.

Adjusting the determined value of margin for inflation

5.97 Power NI has assessed its margin based on an average working capital over the 4 years of the SPC25 Price Control. This approach averages nominal values which allow for an element of inflation. In practice, the value of margin included in tariffs is determined from the formula for St in the licence which requires input values (including the determined value of margin on October 2023 prices (CPIH deflated). We have made a simple adjustment, anchoring the nominal determined value of margin of £16.5m at the midpoint of the SPC25 period (the end of March 2027) and applying the inflation factors used by the company to determine nominal values in its business plan submission. Taking a factor of 1.0823 to convert to October 2023 prices, we arrive at a margin of £15.3m as the allowance for **Pv** (the determined value of margin) in the proposed licence formula for $\mathbf{S_t}$.

5.98 However, we note that the value for the market price for power of £150/MWh is held constant in the calculation of margin in nominal terms. Applying the same approach gives a representative market price for power of £139 at October 2023 prices.

Financeability

5.99 In its response to the draft determination Power NI highlighted that the requirement for Power NI to be financeable or sustainable, is a statutory duty of UR. Power NI expressed its concern that UR did not appear to have undertaken any financeability or scenario testing of the draft determination values.

5.100 Power NI also noted that whilst the onus is on UR to consider its statutory duties, it included its own financial stress testing. Power NI noted that as a 100% equity funded business its focus of financeability and investability measures is on profitability measures rather than on traditional financeability assessment for regulated utilities which focus on assessment of credit metrics. It therefore utilised ratios such as Earnings before Interest and Tax (EBIT) as a % of turnover, EBIT as % of operating costs, notional dividend yield and EBIT as a % of capital employed in its financeability assessment.

5.101 As set out in paragraph 1.12, Article 12 of the Energy Order requires us to carry out our functions in the manner we consider is best calculated to further our principal objective, having regard to the need to secure that licence holders are able to finance the activities which are the subject of licence obligations placed on them (amongst other things).

5.102 This duty is framed similarly to the financing duties of other UK regulators and can broadly be taken in practice to mean that the price control ought to be set at a level which would allow an efficient regulated company to finance the legally compliant performance of its activities which are licensed or which it carries out in consequence of holding a licence.

5.103 We agree that the traditional financeability assessment for regulated utilities is not relevant for Power NI due to its capital structure. We consider that the profitability ratios utilised by Power NI may if set up properly, could help to show how real-life equity investors will look at a business. However, in our opinion, the ratio analysis utilised by Power NI is flawed as it is based on a hypothetical supplier capital requirement rather than on Power NI actual core equity base of circa £100m[20]. This is discussed further in Annex B. Ultimately, we consider that as long as the return on capital is sufficient, then it is for Power NI to identify a suitable approach to dividend policy.

Margin Structure

5.104 The determined margin is based on an assumed market price of electricity of £150/MWh. Recent history has shown the market price of electricity can be highly variable and changes in this price will have an impact on working capital and the cost of financing Power NI.

5.105 In the past the licence has allowed 30% of the $\mathbf{S_t}$ term to vary with the number of customers. This figure of 30% was close to the determined monetary value of the margin. This provided some protection to both Power NI and customers that the allowed margin would vary as the number of customers reduced or increased and that the margin was not a barrier to Power NI taking on new customers.

5.106 However, as Power NI has noted, its margin fell in percentage terms as the cost of energy rose. Conversely, a fixed margin would increase if the cost of energy decreased.

5.107 Looking backwards, a market price of energy of £150/MWh has been exceeded frequently in the recent past. Looking forward, the market price for energy has been lower than the £100 /MWh for most of 2024 and forward prices for energy also appear to be at or below £100 /MWh for the next two years. The most recent Power NI tariff review, effective from December

[20] See the amounts valued at WACC in Table 5.8.

2024, which covers most of the first half of the SPC25 Price Control, is based on a market price for power of £100/MWh.

5.108 In view of the uncertainty over the future market price for energy and the fact that margin is sensitive to this parameter, we consider how much of each component of the capital and the associated margin contribution was related to the market cost of energy. This assessment was based on the company's assessment of capital at £100, 200 and 300/MWh. and how much was fixed. This revealed that 27% of our determined margin at £150/MWh was 'fixed' and the remaining 73% varied with the market price of power (at a fixed number of customers). We have used a simple 25%, 75% split in our subsequent assessment.

5.109 Because of this relationship, we consider it appropriate to make provision for the margin recovered by the company to vary with both customer numbers and market price of power. Our determination is that:

- The 25% or the margin seen to be 'fixed' (at a constant number of customers) will vary in proportion to customer numbers only.
- The 75% of the margin seen to be variable in terms of market price of energy (at a constant number of customers) will be varied in proportion to the product of the proportion of customers and the market price for energy. This recognises that the relationship between the market price of energy is a surrogate for the cost of energy (customer numbers * consumption/customer numbers* market price of energy). We have not factored the actual consumption per customer into our proposals as it adds further complexity. We note that the risk of exceeding the consumption per customer assumed by the company in its assessment of margin is unlikely unless there is a material increase in the rate of LCT connections.

5.110 Therefore, our determination of a factor to vary the determined margin in line with customer numbers and market price of power is:

Allowed margin in any relevant year = Determined margin of £15.3m (in October 2023 prices) * Margin factor

Margin Factor ($\mathbf{MF_t}$) = 25% * CUST + 75%* CUST * MPE

or

Margin Factor ($\mathbf{MF_t}$) = CUST * (25% + 75% * MPE)

Where the value of CUST (number of customers) and MPE (market price of energy) are the ratios of actual value to determined value. In its response to the draft determination, the company noted that:

a) The approach to varying margin in line with number of customers and power price was only reasonable if the determination of base margin was reasonable.

b) That it believes that we had failed to consider the increased risks faced by the business and the business / group needs to effectively ring fence for potential shocks whether they materialise of not – in effect that the business cannot be funded on a retrospective basis.

c) That certain capital requirements of the business are not linear and that certain costs will increase as market prices fall. It suggested that the methodology should contain a floor mechanism to recognise the capitalisation of those items which do not have a linear relationship to or are required regardless of the market price for energy. The company did not provide an estimate of a floor price or more information on the non-linear relationship between capital requirements and movements in energy prices.

5.111 Having considered this response, we note that:

a) For the reasons set out above, we consider the determined base margin is reasonable.

b) Our determination of margin is a reasonable value but is does not, nor is it intended to immunise the company from all risk. However, in determining the margin we have included a number of protections which mitigates the risk to the company:

(i) The determined value of margin includes an uplift on our assessed value of margin which allows, in part, for potential shocks whether they materialise of not.

(ii) Our proposal for varying the margin includes the hedged price of energy which can be accounted for as a forward-looking element each time tariffs are set.

(iii) The G_t cost of credit recovery mechanism provides a further correction mechanism which can be accounted for as tariffs are set.

(iv) The correction mechanism includes an adjustment for customer numbers which can be accounted for as tariffs are set.

(v) The margin includes an element of capital remunerated at a full cost of equity which takes account of an element of risk.

5.112 The final element of the adjustment mechanism which adjusts for the margin in light of DAM prices must, by its nature be a retrospective adjustment. But his is a final protection in a series of other protections which can be accounted for as tariffs are set.

5.113 However, in light of the company's representations on the need for a floor to the mechanism, we have set a floor energy price of £90/MWh (in October 2023 prices), which will place a floor on the average margin over the price control similar to that recovered by the company from the variable element of the margin in 2023/24.

5.114 In view of these considerations, our determination of the value of CUST (number of customers) and MPE (market price of energy) are the ratios of actual value to determined value as defined in Table 5.9 below.

	Determined value	Actual value
CUST	The average number of customers served used by Power NI in its assessment of margin = 576,498	The number of customers as on 30th September in the relevant year.
MPE	The average market price of energy used by Power NI in its assessment of margin (£150/MWh) converted to October 2023 prices: = 139/MWh	the greater of: a. the market price for energy in £/MWh in relevant year t in October 2023 prices being the higher of the average rate of energy price hedged in the year or the highest average price of energy in the DAM for the relevant year (being the highest of the average price of energy in the DAM in Q1, Q2, Q3 and Q4 of relevant year t); b. £90 per MW hour."

Table 5.9: Proposed definition of margin structure terms

5.115 In our view, this approach:

a) Reflects the underlying variability of margin relative to customer number and the market price of power.

b) Is practical in application.

c) Reflects the decisions that Power NI will have to make at any point in time, taking account of the higher of power prices as revealed in forward look hedges and the actual cost of power revealed in the DAM.

d) Moderates the impact of changes in power price and customer numbers on margin as a percentage of turnover.

6. Next Steps

Consultation on licence modifications

6.1 This final determination for the Power NI SPC25 Price Control sets out or conclusions on a range of issues including the structure and form of the price control, the scope and coverage of regulated tariffs, the duration of the control, the operating cost levels and allocations, and allowed margin. Its focus is the determination of Power NI's own costs and the margin necessary to finance its residential supply business. It sets out how these conclusions will inform the calculation of the maximum average charge per unit supplied which Power NI can charge its domestic supply customers.

6.2 We must give effect to our final determination by modifying the company's electricity supply licence. In parallel with this final determination, we have published a separate consultation on proposed licence modifications. Once we have considered the response to that consultation, we intend to publish a final decision on licence modifications in June 2025.

6.3 There is then an opportunity for the licence holder subject to the price control, any other licence holder materially affected by the decision, a qualifying body or association representing one of those licence holders, and/or the Consumer Council for Northern Ireland to appeal the decision on the proposed licence modifications to the CMA.

6.4 If our decision on licence modifications is not subject to an appeal, they will come into effect 56 days after the publication of the licence modification decision, in line with the requirements of Article 14(10) of the Electricity (Northern Ireland) Order 1996. However, the modified price control is such that the modifications will be treated as being applicable with effect on and from 1 April 2025.

6.5 Table 6.1 provides an overview of the next steps and timelines for the SPC25 Price Control licence modification process.

Date	Milestone
24 April 2025	UR publishes final determination and proposed licence modifications.
23 May 2025	Consultation on licence modifications closes.
30 June 2025	Decision on licence modifications published.
25 August 2025	Licence modifications become effective.

Table 6.1: Key milestones

Further work

6.6 In line with good regulatory practice, we continue to monitor delivery of the price control and engage as we always do on a process of continuous improvement which will inform the development of the next price control for Power NI, namely SPC29.

6.7 As part of this process, we will continue to seek feedback from Power NI and a range of other key stakeholders on key aspects of the price control process. We will use this information as we continue to develop and improve our price control processes.