



An Coimisiún
um Rialáil Fónais
**Commission for
Regulation of Utilities**

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Commission for Regulation of Utilities

Price Review Six

Impact Analysis Note

Information Paper

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CRU Strategic Plan 2025-27

Vision, Purpose, and Values



OUR VISION:

Resilient, efficient, sustainable, and safe energy and water services for Ireland.



OUR PURPOSE:

We actively serve the public interest by regulating the provision of energy and water to Irish homes and businesses, while supporting the transformation to net zero.



OUR VALUES:

• Integrity • Professionalism • Openness • Accountability

Executive Summary

This Information Paper analyses how the Price Review Six (PR6) Final Determination will impact both electricity customers and network companies. It should be read alongside the PR6 Final Determination papers for distribution (CRU2025194), transmission (CRU2025195) and offshore (CRU2025196). The purpose of this impact analysis note is to provide transparency on the Final Decision and enable stakeholders to understand the cost impact of the Commission for Regulation of Utilities' (CRU) PR6 decisions. The paper addresses two main questions:

1. **Impact on network companies:** How will the PR6 Final Determination affect the operations, responsibilities, and financial position of EirGrid and ESB Networks?
2. **Impact on customer network charges:** How will the revenue allowances affect electricity network charges for different types of customers, from households to large industrial users?

Context to PR6

PR6 represents a critical juncture in Ireland's energy transition, covering 2026-2030 when the country must make substantial progress towards ambitious decarbonisation targets including 80% renewable electricity by 2030. The strategic context is shaped by major policy developments including Ireland's first carbon budget programme, successive Climate Action Plans, and European policies aimed at achieving carbon neutrality by 2050. Delivering on these ambitions will require a step-increase in the level of investment in electricity networks in Ireland.

Under this policy backdrop, network companies face several challenges in PR6 including competition for limited global supply chains, rapidly expanding workforce requirements, and substantial financing needs – particularly for EirGrid which must transition from an asset-light to asset-heavy business as it starts to own, operate and maintain offshore transmission assets. The CRU has therefore adapted the regulatory framework from Price Review Five (PR5) to enable the required investment whilst ensuring customers continue to receive value for money.

Impact on Network Companies

The PR6 Final Determination represents a material evolution for Ireland's network companies, providing them with substantially increased funding alongside enhanced responsibilities and accountability. The regulatory framework has evolved to address the challenges companies face in PR6.

- **Enhanced Regulatory Framework:** Network companies will operate under a regulatory framework that provides greater certainty through a two-tier allowance structure – baseline allowances for activity that is more certain, and additional allowances

accessible through reopener mechanisms, governed through the Agile Investment and Monitoring Framework (AIMF). This framework gives companies more operational flexibility whilst ensuring clear accountability for delivery through Delivery Obligations that ring-fence funding to specific outputs.

- **Streamlined Performance Framework:** The incentive regime has been refined to focus on 26 outcome-based measures that directly impact customer value, with mechanistic targets set in advance to provide operational certainty. This reduces administrative burden whilst ensuring strong accountability, with the Transmission Asset Owner (TAO) receiving an enhanced incentive package reflecting its expanded delivery responsibilities.
- **Substantial Funding Increases:** Cost allowances have increased dramatically across all network companies – the Transmission System Operator (TSO) receives over double its PR5 allowance (€1.6 billion controllable baseline), the TAO also receives over double its previous allowance (€3.2 billion controllable baseline), and the Distribution System Operator (DSO) receives a 50% increase (€8.1 billion baseline). For the first time, EirGrid will receive offshore funding ranging from €1.2 billion to €4.9 billion depending on the number of offshore transmission assets that will transfer onto its balance sheet during PR6.
- **Supportive Financial Framework:** The CRU has implemented targeted changes to the cost of capital framework, including separate rates recognising each company's distinct risk profile and a bespoke offshore framework designed to attract the billions in private investment required. These changes ensure companies can access necessary financing whilst protecting customers from excessive costs.

Impact on Customers

Table 1 below shows a summary of the CRU's current assessment of the impact on customers of the PR6 Final Determination, showing estimated movements from the final full tariff year of PR5 (2024-25) to the final full year of PR6 (2029-30) for a range of different customer groups, accounting for all network charges. The table shows the estimated impact on network charges under both the baseline allowance and a high scenario (where all the additional funding available through the AIMF is utilised by all licensees and 6 Phase 1 offshore projects are transferred to EirGrid as the Offshore Asset Owner (OAO) during PR6).

Table 1: Summary of Impact of PR6 Final Determination on Consumers (Nominal Values)

		Baseline Scenario		High Scenario	
Example Customer	2024-25, €	2029-30, €	Change	2029-30, €	Change
Domestic	384	442	+59 (+15%)	490	+106 (+28%)
Small non-domestic	3,481	3,967	+486 (+14%)	4,402	+920 (+26%)
Medium non-domestic (1)	95,070	102,179	+7,109 (+7%)	114,279	+19,209 (+20%)
Medium non-domestic (2)	657,945	584,789	-73,155 (-11%)	666,739	+8,795 (+1%)
Large non-domestic	1,527,840	1,391,740	-136,100 (-9%)	1,582,757	+54,918 (+4%)
XLEU	6,758,543	5,379,773	-1,378,770 (-20%)	6,351,624	-406,919 (-6%)

The CRU's PR6 Final Determination aims to provide a balance between (a) the need to enable the network companies to deliver on the PR6 strategic objectives, and (b) the need to safeguard the interests of current and future electricity consumers.

Through the investment being allowed through the Final Determination, PR6 will enable the delivery of substantial infrastructure improvements including 29 priority transmission projects which would unlock significant network capacity, major distribution network reinforcement which would create additional capacity nationwide, comprehensive storm resilience measures, and capability to maintain offshore transmission assets supporting more than 5 GW of offshore wind capacity. The Final Determination also aims to support electrification targets including 1 million electric vehicles (EVs) and 680,000 heat pumps, whilst connecting 4.4 GW of renewable generation to the distribution system.

Estimated PR6 impacts on network charges vary across different customer types. Generally, charges related to the distribution network are increasing, whereas transmission charges are decreasing. Much of the PR6 investment driving increases is on the distribution network, while part of the current transmission allowances are profiled to drop off. These increases and decreases impact the various customer types differently.

Any analysis of estimated increases/decreases is heavily dependent on what is being compared against. If the estimated network charges by the end of PR6 are compared with 2020-21 network charges, the increases and decreases look different. In the initial PR6 investment scenario, from 2020-21 to 2029-30 the example domestic customer is estimated to experience a 51% increase in network charges, whereas some of the larger electricity users would be seeing

over 100% increases (e.g. the example large non-domestic customer is estimated to experience a 131% increase).

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
AIF	Agile Investment Framework – PR5
AIMF	Agile Investment and Monitoring Framework – PR6
ATV	Asset Transfer Value
Capex	Capital Expenditure
CRU	Commission for Regulation of Utilities
DAO	Distribution Asset Owner
DG	DUoS Group
DSO	Distribution System Operator
DUoS	Distribution Use of System
D-TUoS	Demand Transmission Use of System
EV	Electric Vehicle
FASS	Future Arrangements for System Services
G-TUoS	Generator Transmission Use of System
KWh	Kilowatt hour
OAo	Offshore Asset Owner
OARP	Offshore Asset Readiness Programme
OE	Ongoing Efficiency
OG-TUoS	Offshore Generator Transmission Use of System
Opex	Operating Expenditure
ORESS	Offshore Renewable Electricity Support Scheme
PR5	Price Review Five
PR6	Price Review Six
RES-E	Renewable Energy Source – Electricity
RoRE	Return on Regulated Equity
RPE	Real Price Effect
TAO	Transmission Asset Owner
Totex	Total Expenditure
TOU	Time of Use
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
XLEU	Extra Large Energy User

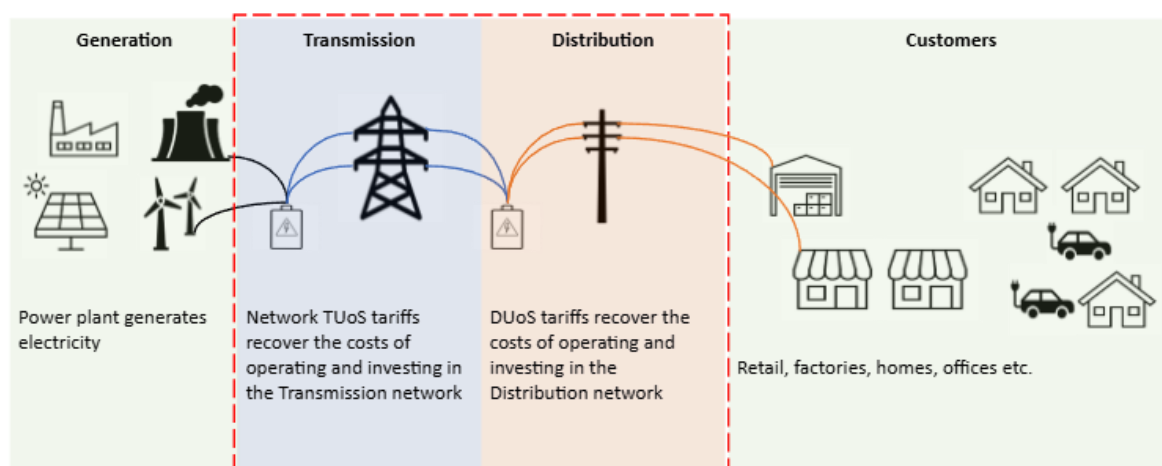
1. Introduction

This paper outlines the potential impact of the PR6 Final Determination. The analysis is intended to allow for meaningful engagement from affected groups, including consumers, industry, advocacy groups and the network companies themselves. Conducting this impact analysis helps to ensure that the decisions by the Commission for Regulation of Utilities (CRU) are supported by clear, accessible information. This will hopefully enable stakeholders to evaluate potential implications more effectively.

Network tariffs impact all end-users' electricity bills. Electricity network tariffs recover the cost of developing, operating, and maintaining the network from connected users. Network costs are one of four components (alongside wholesale costs, supply costs, and taxes/levies) that constitute an electricity consumer's overall electricity bill.

Figure 1 below provides a conceptual overview of the electricity system from generation to customer supply. The network costs relate to the section enclosed by red dots in the diagram.

Figure 1: Electricity System General Overview



In this paper, we present an analysis of the impact of key decisions related to the PR6 Final Determination on:

- **The network companies**, in terms of the cost allowances they have been provided and the associated delivery obligations, the incentive framework they will be subject to, and the financial framework that will be used to support their investment plans. We also present the impact of this on the overall revenue allowances provided to the network companies.
- **Customers** in terms of the impact on archetypical customer network charges in 2029-30 (the final tariff year entirely in PR6) relative to 2024-25 (representing the final tariff year

entirely in PR5).¹ We present the impact on different types of customers, such as domestic and non-domestic customers, separately. We also separately present the impact on transmission charges, distribution charges, and other network charges. Finally, we summarise our analysis of what is driving any changes in network charges.

We present the network company cost and revenue values (e.g. PR6 network company asks and CRU PR6 allowed revenues) in 2024 monies, unless stated otherwise, to ensure consistency across PR6 papers. However, we present the estimates on consumer network charges in nominal terms², unless otherwise stated, to provide a more realistic portrayal of potential future costs for electricity customers. The details and figures in this paper constitute an update since the Draft Determination version of this paper (CRU202591). We have made several assumptions and simplifications in the analysis, and so the figures should be considered as indicative current estimates only. Furthermore, these estimates are highly sensitive to changes to related forecasts (see Section 6.1). The figures presented are not intended as a statement of actual or future tariffs.

1.1 Structure of Paper

This paper is structured as follows:

- **Section 2 (Background to the PR6 Final Determination)** provides the context underpinning PR6 and summarises the key features of the PR6 Final Determination.
- **Section 3 (Impact on Companies)** presents our view of the impact of the PR6 Final Determination on the network companies, EirGrid and ESBN.
- **Section 4 (Impact on Domestic Customers)** outlines the estimated PR6 impact on domestic customers.
- **Section 5 (Impact on Non-Domestic Customers)** outlines the estimated PR6 impact on non-domestic customers.
- **Section 6 (Further Information on Network Charges)** provides further analysis regarding impacts across customer types and details on how these estimates are subject to change.
- **Section 7 (Related Topics)** provides details of some CRU workstreams (some within PR6 and some separate to PR6) which are relevant to the wider discussion of consumer impacts.

¹ It should be noted that, 2024-25 charges include costs which were not envisaged at the start of PR5 (such as costs relating to the [Security of Electricity Supply - Programme of Actions](#)).

² Inflation forecasts have been updated since Draft Determination.

- **Section 8 (Conclusion and Next Steps)** concludes and outlines future plans for this assessment.
- **Appendix A:** Methodology for Estimating Network Charge Impacts provides a summary of the methodology used to estimate the impact on customers.

2. Background to the PR6 Final Determination

This section provides the policy context and background to this impact analysis. It provides the background to the CRU's price review process, outlines the strategic objectives of PR6, and it provides a summary of the PR6 Final Determination.

2.1 The CRU's Role

The CRU is Ireland's independent energy and water regulator, with a mission to protect the public interest in Water, Energy and Energy Safety. The CRU is committed to helping deliver a secure, low carbon future at the least possible cost, while ensuring energy security and protecting the interests of all consumers.

In the electricity sector, the CRU is responsible for the economic regulation of system operators and asset owners for electricity transmission and distribution systems in Ireland (collectively referred to as "network companies"). The CRU's role is to protect electricity customers by ensuring that network companies spend customers' money appropriately and efficiently to deliver necessary services and make necessary investments in infrastructure.

This responsibility is exercised through Price Reviews, which are conducted every five years and set the revenues that network companies can recover from electricity consumers. Under Section 35 of the Electricity Regulation Act 1999, the CRU approves charges for the use of the electricity transmission and distribution system in Ireland. These charges must be calculated to enable network companies to recover the appropriate proportion of costs directly or indirectly incurred in carrying out necessary works, plus a reasonable rate of return on capital.

The CRU's regulatory oversight extends to:

- **EirGrid:** Licensed as the TSO and, following the Government's approval of the Offshore Electricity Transmission System Policy in April 2021, designated as the offshore system operator and asset owner.
- **ESB Networks (ESBN):** Licensed as the TAO and Distribution Asset Owner (DAO), with ESBN Designated Activity Company also licensed as the DSO.

2.2 Electricity Network Tariffs

The revenue allowances set through these Price Reviews are recovered through network charges applied to both electricity users and generators connected to the network, though this paper focuses solely on the impact on electricity customers. For electricity customers, these charges are collected from suppliers and passed on through electricity bills.

The network charges for electricity customers currently comprise two main components:

- Distribution Use of System (DUoS) charges, which relate to the distribution system and provide revenues for the DSO.
- Demand Transmission Use of System (D-TUoS) charges, which relate to the transmission system and provide revenues for the TSO, TAO and OAO.³

Additionally:

- Future Arrangements for System Services (FASS)⁴ is a new charge (separate to TUoS) which is due to begin during PR6. This charge will recover the TSO costs for the securing of system services required to support system stability and resilience. FASS replaces DS3 system services which is currently funded through the D-TUoS charges. While FASS costs will be recovered separately from D-TUoS charges, current indicative estimates are included in this analysis for completeness to aid comparison with 2024-25 where DS3 system services costs were included in D-TUoS. For reference, indicative FASS estimates are delineated in A.4.

These charges are levied on electricity suppliers,^{5,6} who determine what level to absorb or pass on to their customers through billing. For the purposes of this paper, the values shown for customer impacts are those that would be charged to the customer's supplier under each scenario, unless stated otherwise.

2.3 Rationale for Intervention and Background to PR6

The introduction of the current Price Review (PR5, 2021-2025) represented a significant evolution towards output-based regulation, with increased focus on delivering specific performance measures including network reliability, customer service, and decarbonisation metrics. One key change was the introduction of the Agile Investment Framework (AIF), which allows network companies to request additional funding or reallocate existing budgets when unexpected needs arise or circumstances change, ensuring that essential network investments can proceed even when they were not fully anticipated at the start of the period.

Looking back at PR5 so far, while network companies have performed well in certain areas such as transmission system reliability and distribution flexibility, key challenges remain, particularly

³ More details on the offshore tariff treatment can be found in the Price Review Six Offshore Final Determination Paper (CRU2025196).

⁴ [SEM-25-007 - All-Island System Services Supplier Charge](#)

⁵ For DG10 customers, ESBN bills the DG10 DUoS network costs directly from EirGrid (TSO).

⁶ Some of the very large customers act as their own suppliers.

around customer interruptions on the distribution network and renewable energy integration targets on the transmission system. Experience from PR5 has also shown that the regulatory framework needs refinement – the AIF has been less effective than expected in managing the significant changes that occurred during the period, and while performance incentives targeted areas important to customers, they did not consistently drive all the desired outcomes. The framework sometimes lacked clear definitions of what network companies were expected to deliver for their allowed revenues, making it difficult to assess whether customers received value for money when additional funding was provided.

PR6 represents a critical juncture in Ireland's energy transition, covering the period 2026-2030 when the country must make substantial progress towards its ambitious decarbonisation targets. The strategic context for PR6 is shaped by major policy developments at both national and European levels, including Ireland's first carbon budget programme approved by the Government, successive Climate Action Plans with increasingly ambitious targets, and European policies driving towards carbon neutrality by 2050.

In addition, network companies face significant deliverability constraints as they compete for limited global supply chains for essential equipment and materials, while simultaneously needing to rapidly expand their workforce capabilities to manage complex infrastructure projects. The financing requirements are substantial, particularly for EirGrid which must transition from an asset-light to asset-heavy business model to accommodate offshore wind development, requiring access to billions of euros in capital markets. These challenges are compounded by ongoing macroeconomic uncertainties including inflation pressures, interest rate volatility, and supply chain disruptions that can significantly impact project costs and timelines.

Recognising these complexities, the CRU considers PR6 to be an evolution of the regulatory framework introduced in PR5, incorporating targeted changes designed to enable the unprecedented level of investment required while ensuring that customers continue to receive value for money.

2.4 PR6 Strategic Objectives

In response to these challenges and opportunities, the CRU has set out, via the PR6 Strategy Paper (CRU202427),⁷ three overarching outcomes that it expects electricity network companies to deliver throughout PR6:

⁷ [CRU202427 PR6 Strategy Paper](#)

- **Decarbonised electricity:** Network companies must facilitate the realisation of Ireland's decarbonisation ambitions, enabling high levels of renewable electricity integration and driving an environmentally sustainable, low carbon energy system. This aligns with Ireland's commitment to achieve 80% renewable electricity by 2030 and supports the broader goal of carbon neutrality by 2050.
- **Secure and resilient networks and supplies:** Network companies must ensure safe, secure, resilient electricity networks and supplies, managing risk and system adequacy appropriately while complying with relevant standards to provide services which customers can rely on. This is particularly crucial given the increasing complexity of the energy system and the need to maintain reliability during the transition period.
- **Empowered customers:** Network companies must deliver high quality and reliable services to customers, ensuring their voice is heard and reflected in the work they do, and that the cost of the transition is minimised. This reflects the CRU's commitment to protecting consumer interests while facilitating necessary system transformation.

To ensure delivery of these key outcomes, the CRU has set five core objectives for all network companies:

- **Deliver infrastructure at pace:** This objective focuses on supporting decarbonisation, realising Ireland's renewable energy and climate change targets, and reducing the cost of constraints to consumers. Accelerated delivery timelines for renewable connections and network infrastructure to meet Housing for All and National Development Plan targets are required.
- **Enhance system efficiency:** Network companies must continuously improve operations and delivery while meeting network needs and protecting customer interests. This includes optimising energy system performance, maximising use of existing assets, and developing innovative whole-of-system solutions involving all customers.
- **Ensure compliance with security of supply standards:** Companies must efficiently manage and develop networks to maintain safe, reliable supplies that are resilient to physical, climate, and cyber shocks. This includes addressing local security of supply issues that have emerged due to significant demand growth, particularly in the Dublin region.
- **Drive smarter, flexible, more digitally enabled networks:** This strategic enabler focuses on transforming network operations with new technologies to improve capabilities and ongoing efficiency. It emphasises the importance of high-quality,

accessible data for managing network capacity and the increasing volumes of distributed generation and connected assets.

- **Customers at the heart of business planning and decision making:** This objective ensures that customers' voices are heard and reflected in network companies' work, with transparent and timely sharing of high-quality information to enable meaningful stakeholder engagement.
- For EirGrid specifically, PR6 includes an additional objective: **successfully establish OAO functions and operations**. This reflects EirGrid's designation as offshore system operator and asset owner, requiring a fundamental transformation from an asset-light to an asset-heavy business model.

The transition to a low carbon future will require additional investment, which will be passed on to customers through electricity bills. Recognising this, the CRU expects network companies to ensure ambitious and systematic focus on increasing efficiency in terms of cost and quality of delivery. The regulatory framework for PR6 builds on the progress made through PR5, which represented a significant evolution towards increased importance on delivering specific outputs aligned with overall outcomes and objectives.

2.5 Summary of PR6 Final Determination

On 03 July 2025 the CRU published its PR6 Draft Determination. A 10-week consultation period followed, ending on 11 September 2025. The CRU then considered the responses received and worked to reflect necessary updates appropriately in the PR6 Final Determination. The PR6 revenues and other relevant figures have been updated in this paper to reflect the Final Determination. The impact modelling has been updated since the Draft Determination to incorporate the figures from the Final Determination and also to include some modelling revisions. Some extra and updated information has also been included in this version of the paper following further consideration and also following the review of the responses received from the consultation period. We hope the further details included provide improved clarity for stakeholders.

The CRU has developed a regulatory package for the Final Determination that aims to meet the strategic objectives for PR6 described in Section 2.4:

- **Increased investment allowances:** To deliver the infrastructure needed for a decarbonised, secure and resilient energy system, there has been a roughly 80% increase in controllable cost allowances compared to PR5, with scope for further increases during the price review period. The CRU has focused these baseline

allowances on critical projects that deliver real improvements in outcomes, using delivery obligations to ensure spending is targeted effectively.

- **Rigorous cost assessment:** The cost assessment process of the CRU and its advisors have recognised the need for network companies' major programmes to deliver decarbonised electricity and secure, resilient networks. However, the CRU has requested further justification for more speculative requests that lack strong business cases, and has assumed greater scope for ongoing efficiencies than indicated in company plans. The regulatory framework seeks to improve transparency about what customers will receive and ensure increased focus on delivery.
- **Enhanced flexibility framework:** To manage uncertainty and provide flexibility, PR6 introduces an enhanced AIMF that is more structured and streamlined than the approach in PR5. This includes mechanisms such as reopeners and volume drivers that can provide additional funding when companies need to respond to changes in project scope, costs, volumes or timings during the control period. Baseline allowances generally remain flexible for companies to use across their portfolio of activities.
- **Clear delivery expectations:** The introduction of 36 Delivery Obligations through the PR6 AIMF provides certainty about what network companies have been funded for and are expected to deliver. This framework focuses on the specific outputs associated with funded allowances, providing transparency to enable robust monitoring and governance by the CRU during the period and when assessing final outcomes.
- **Streamlined performance incentives:** An outcomes-based suite of 26 performance incentives aims to ensure network companies are motivated to improve performance in areas that matter most to customers. The CRU has removed duplicative or process-focused incentives in favour of more direct outcome-based measures. Targets are set in advance, providing companies with certainty and ensuring efforts focus on activities that drive the most value for customers.
- **Financial resilience:** To ensure companies can finance the major increase in investment, the CRU has assessed relevant cashflow, profitability and leverage metrics used by credit rating agencies. This analysis indicates that the network companies would obtain a comfortable investment grade credit rating based on the PR6 proposals, even when stress-tested against plausible future scenarios and excluding any support from state ownership.

2.6 Customer Value to be Delivered in PR6

Through the additional investment being allowed, PR6 is expected to deliver the following for customers, based on the companies' business plan submissions.

2.6.1 Transmission Network

- **29 priority infrastructure projects** are projected to be energised or reach target project stages by the end of PR6, progressing work to unlock over 22,000 MVA of additional capacity to maintain security of electricity supply and reduce costly constraints on the transmission network.
- **A new state-of-the-art control centre** for the TSO to support Ireland's transition to a smart, flexible, low-carbon electricity system, directly supporting government decarbonisation goals.
- **Additional transmission projects** including 37 ultra-high voltage and offshore connection projects to be progressed by the TAO, further increasing network capacity alongside the priority projects that form the core delivery obligations for PR6.
- **Offshore wind infrastructure capability** to be established through EirGrid's new OAO function, including delivery of the Offshore Asset Readiness Programme (OARP) and operations and maintenance capabilities to support more than 5 GW of offshore wind capacity.
- **Advanced system management tools** expected to be implemented through continued investment in TSO systems, capabilities and tools to reliably manage a low-carbon electricity system while supporting continued expansion of renewable energy connections.

2.6.2 Distribution Network

- **Major high-voltage network reinforcement programme** to provide additional 110kV transformer capacity of 3,600 MVA and a further 380 MVA of firm capacity at MV from 38 kV projects, with specific delivery obligations to ensure measurable capacity improvements are achieved.

- **Comprehensive pole replacement strategy** of around 28,670 poles⁸ to address risks from Ireland's ageing electricity infrastructure by maintaining asset health standards, alongside targeted investment in high-voltage station replacements to ensure continued reliable supply.
- **Smart grid technology upgrades** including substantial investment in operational systems, control infrastructure and digital capabilities essential for creating a more intelligent, flexible and responsive distribution network.
- **Support for electrification targets** aligned with Climate Action Plan goals, enabling connection of 1 million EVs and 680,000 heat pumps, while facilitating low-carbon technology adoption by customers and connecting 4.4 GW of renewable generation to the distribution system during PR6.
- **Enhanced storm resilience programme** involving €1.0 billion of investment to implement lessons learned from Storm Éowyn and build on the Winter 2025 Grid Resilience Plan, adopting robust approaches to network planning, customer service, vulnerable customer protection, organisational resilience and storm damage repair.

⁸ This includes 24,160 MV pole replacements and 4,500 LV pole replacements, to ensure a safe, reliant, and resilient network.

3. Impact on Companies

In this section, we describe the impact on companies in PR6 as a result of the broader changes in scope and objectives of the PR6 Framework. We present the key impacts in terms of:

- the regulatory and incentive framework that the network companies will be required to operate under,
- the cost allowances that they have been given over PR6 and the delivery expectations associated with those cost allowances,
- the financial policy framework underpinning the investment the network companies will be making over PR6, and
- the impact in terms of overall revenue allowances.

3.1 PR6 Regulatory Framework

The network companies have been provided with a substantial increase in their cost allowances and a supportive financial framework to scale up their operations and meet PR6's strategic objectives. Alongside this increased funding, the PR6 regulatory framework also places greater responsibility and accountability on network companies to deliver measurable outcomes for customers.

However, significant uncertainties remain around many elements of PR6 that will influence both the volume and type of investment required over the next five years:

- **Uncertainty around decarbonisation pathways** – The exact route to achieving Ireland's climate targets may evolve, affecting investment priorities and timing.
- **Delivery challenges** – Companies must overcome constraints in workforce capacity and global supply chains that could impact project timelines and costs.
- **Uncertainty around demand growth and cost recovery** – The forecast growth in electricity demand that drives the need for network reinforcement may not materialise as expected, affecting cost recovery.

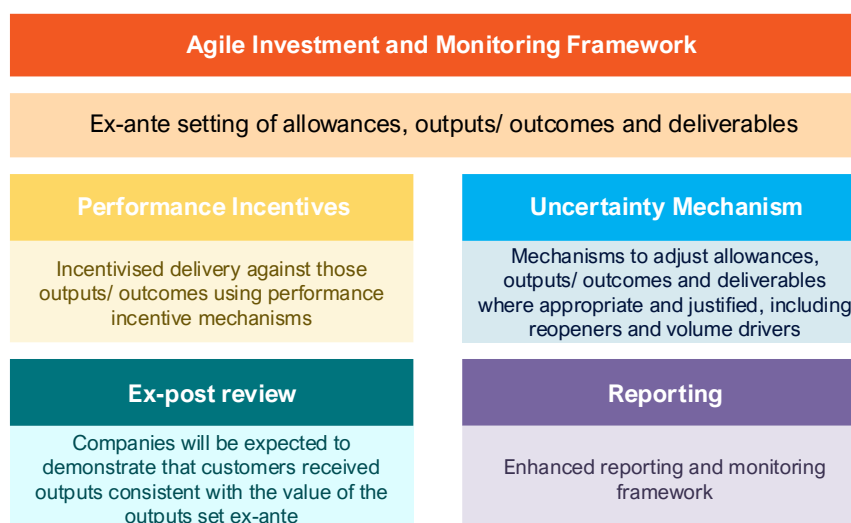
To help companies manage these uncertainties while ensuring strong performance, the CRU has developed a regulatory framework that provides network companies with clear funding commitments and specific output obligations. This is complemented by a suite of flexibility mechanisms that can adjust cost allowances upward or downward during the control period to respond to changes in the size and scope of investment actually required.

This approach aims to balance the need for network companies to have certainty in planning major infrastructure investments with the flexibility to adapt to changing circumstances, while ensuring customers receive value for money regardless of how these uncertainties unfold.

3.1.1 The Agile Investment and Monitoring Framework (AIMF)

The AIMF plays a central role in PR6, building on lessons learned from PR5 to be more clearly defined and structured. It is designed to give companies certainty about revenue recovery by enabling them to recover additional investment as plans evolve, while adding transparency through an in-period reopener process. This approach ensures companies can access additional funding as investment needs become clearer, while protecting customers from premature or inefficient spending. The scope of the AIMF is presented in Figure 2.

Figure 2: Overview of the PR6 Agile Investment and Monitoring Framework



To ensure customers do not bear the risk of funding a significant increase in allowances without seeing promised performance improvements and delivery, the CRU has created a two-tier allowance structure:

- **Baseline allowance** – This includes critical projects that are explicitly linked to specific outputs or deliverables. Part of this allowance is ring-fenced for delivery of specific outputs through formal ‘Delivery Obligations’ that companies must meet.⁹
- **High allowance** - This is the baseline allowance plus additional funding available through AIMF mechanisms such as reopeners and allowances that are linked to the volumes delivered. Companies can access this additional funding once there is greater certainty about the work required, but they must provide strong justification to the CRU for any extra investment.

⁹ As part of the baseline allowance, a delivery obligation ring fences money for a specific output.

While part of the baseline allowance is tied to specific delivery obligations, network companies retain important operational flexibility. They can reallocate priorities and revenues within bundled delivery obligations where needed, provided they remain within their overall allowance or agree any material changes through the reopener process. The remainder of their allowance functions as an aggregate funding pot with flexibility to allocate across outputs and deliverables at the portfolio level.

Table 2 presents the framework that will be used to assess the performance against the delivery obligations *ex-post* and the impact on companies.

Table 2: Company Impacts based on Possible Scenarios of Delivery Obligation Completion

	Capex	Opex
Inefficient overspend	Costs disallowed - cannot be recovered in PR6 or future price reviews	Costs disallowed - cannot be recovered
Efficient overspend	Adjustment made in PR7 to reflect cost of capital and depreciation	Allowed during PR6 once proven efficient
Efficient saving	Company retains cost of capital and depreciation benefits for five years, through an adjustment made to PR7 revenues	Company keeps underspend in PR6, with efficient savings typically feeding into PR7 baseline
Efficient deferral (different from under/non-delivery)	Company retains cost of capital and depreciation benefits during PR6, no PR7 adjustment	N/A

The PR6 reporting requirements for delivery obligations make progress monitoring more effective and give companies greater opportunity to request changes to project definitions, costs, and milestones in-period. The PR6 regulatory framework has streamlined the process by directly mapping funding to specific work deliverables, making reviews more efficient and mechanistic.

Two key uncertainty mechanisms support the AIMF:

- **Volume Drivers** – Provide funding certainty for activities where unit costs can be determined in advance, but the total volume needed over the period is uncertain.
- **Reopeners** – Allow companies to access funds beyond baseline allowances by submitting narrative and engineering justification documents. Companies can also request changes to delivery obligation definitions through this process.

This framework gives companies more funding and operational flexibility while increasing focus on delivery, performance and monitoring. Delivery obligations ensure progress on critical projects while remaining open to updates, providing companies with greater control over their programmes. The approach supports ambitious investment at scale, but only where there is clear delivery and measurable outcomes for customers.

3.1.2 Performance Incentives

The performance incentive regime is a key component of the PR6 regulatory framework, covering the output-based metrics on which network companies must monitor and report, the targets associated with each metric, and the financial rewards and penalties for meeting or missing those targets.

The PR6 performance incentive regime represents an evolution from PR5, with two main changes that will impact how network companies operate:

- **More streamlined and focused target setting** – The incentives have been adjusted to focus on the ones that directly impact customer value, while the design of the incentives has evolved to replace the incentivisation of interim processes, with mechanistic, outcome-based metrics and targets that are set in advance.
- **Enhanced accountability** – The revised incentive regime creates stronger alignment between incentive strength and customer value, with penalties and rewards that are financially proportionate to the importance of each metric. While the overall strength of the performance incentive regime for the DSO and TSO is maintained from PR5, the size of the TAO incentive package has been increased with the addition of new incentives, and the strength of individual incentives have been rebalanced to focus on the most important outcomes.

These changes are aligned in many areas with the proposals put forward by the network companies and have followed significant engagement between the CRU and the network companies. The overall regime is designed to focus on the outcomes that matter for customers, while the targets have been designed to be stretching but achievable and within the companies' control.

Table 3 provides an overview of the key features of the incentive framework in PR6.

Table 3: Overview of PR6 Performance Incentives for the Network Companies

	DSO	TSO	TAO
Overall package of incentives	A total of 14 incentives (1 incentive retired): 11 incentives retained from PR5 with amendments, including 1 joint TSO/DSO incentive 3 new incentives	A total of 11 incentives: 8 incentives retained from PR5 with amendments, including 1 joint TSO/DSO incentive 1 new incentive 2 joint TSO/TAO incentives, with new metrics	A total of 4 incentives: 1 incentive revised from PR5 1 streamlined incentive with new metric 2 joint TSO/TAO incentives, with new metrics
Size of package in annual terms and as a percentage of RoRE	+€68m / -€64m (+1.65% / -1.57%)	+€14m / -€6m (+12.36% / -5.49%)	+€16m / -€16m (+0.75% / -0.75%)
Key areas of focus	Reliability (interruptions, unplanned outages), customer service (satisfaction scores, complaint resolution), vulnerable customer support, and connection delivery for both generation and demand customers.	Renewable energy integration (RES-E percentage, system non-synchronous penetration, renewable dispatch down), system reliability (system minutes lost, frequency control), imperfections, and connection delivery timelines.	Infrastructure and project delivery (delivery of new and uprated overhead lines, new underground cable and new substations)

The revised incentive framework provides several improvements for the network companies. Setting targets in advance, where possible, gives companies greater certainty by providing clear performance expectations they can build into business planning from the outset. The mechanistic nature of the metrics reduces administrative burden by eliminating subjective assessments and streamlining reporting requirements, allowing companies to focus resources on delivery rather than process management. Finally, the focus on outcome-based measures enables companies to prioritise activities that directly benefit customers, whilst the CRU's commitment to publishing an annual performance dashboard will provide enhanced transparency and clear visibility of company performance against targets.

3.2 Cost Allowances

The PR6 framework provides network companies with substantially larger funding envelopes, coupled with greater clarity on expected delivery and performance, and enhanced reporting requirements to ensure transparency and accountability.

A key evolution from PR5 is the upfront inclusion of adjustments for input price pressures (referred to as real price effects (RPEs)) and year-on-year productivity improvements (referred to as ongoing efficiency (OE)) within the controllable operating expenditure (opex) cost allowances.

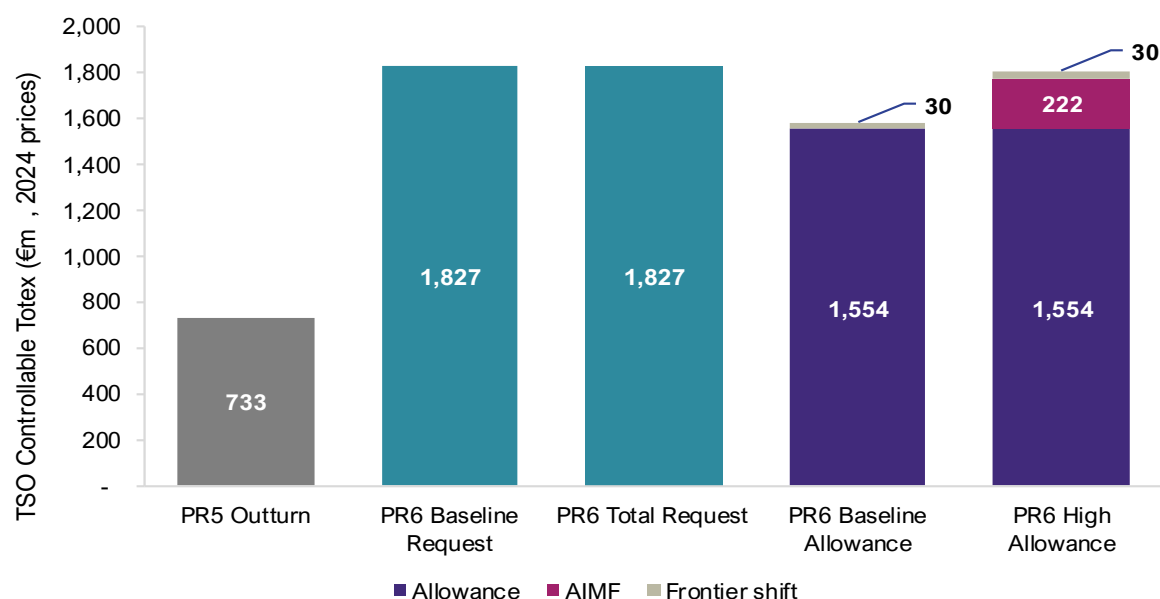
Given the scale of the planned investment over PR6 and exposure to volatile input costs and supply chain risks, the CRU has considered that the PR5 approach of *ex-post* cost adjustments is likely to be insufficient and ought to be replaced by RPEs and OE, combined into a frontier shift. Therefore, the PR6 cost allowances include a frontier shift for both the baseline and high scenario, but the company asks do not.

3.2.1 TSO Allowance

Controllable Costs

For controllable elements of the TSO's cost base, the CRU has provided the TSO with a baseline allowance of approximately €1.6 billion (2024 prices) over PR6, which represents a doubling of the allowance relative to expected outturn spend in PR5, as shown in Figure 3, and a €153 million increase relative to the allowance proposed at the Draft Determination. This covers €717 million of capital expenditure (capex) and €837 million of controllable opex with an additional €30 million for expected input price pressures and future efficiencies ("frontier shift"). This higher allowance reflects the increased complexity and scale of system operation required to support Ireland's decarbonisation ambitions.

Figure 3: Comparison of TSO Controllable Costs: PR5 Outturn, PR6 Request and PR6 Allowances (€m, 2024 prices)



Within this baseline controllable allowance of €1.6 billion, 23% of the capex is ring-fenced through specific delivery obligations covering priority network projects¹⁰ and the development of

¹⁰ For more details, please refer to the PR5 and PR6 TSO and TAO Capex Cost Assessment report.

a control centre to support Ireland's transition to a smart, flexible, low-carbon electricity system. The TSO will be expected to report against the delivery of these projects on a quarterly basis.

The CRU's baseline allowance is lower than the TSO's request, as the TSO had provided insufficient justification for some of its proposed expenditure. There are also inherent uncertainties around the scale and deliverability of some projects, which means the associated costs have been excluded from the baseline allowance and instead included as an uncertainty mechanism within the AIMF. For example, whilst full funding has been provided for priority projects, about 73% funding has been allowed for other projects, subject to reopener applications.

The TSO has access to four reopeners that allow the upward adjustment of allowances on a needs basis for both network and non-network activities. Assuming all the re-opener mechanisms are used, the associated high allowance will be €1.8 billion – which is approximately 1.2% lower than the TSO's PR6 request.

Non-Controllable Costs

Beyond the controllable allowance, the TSO is expected to spend €745 million over PR6 on exceptional cost items mostly related to the security of supply programme, and a further €366 million on non-controllable costs.¹¹ These costs will be treated as pass-through and are unchanged from the Draft Determination.

3.2.2 TAO Allowance

Controllable Costs

For the TAO, the CRU has provided a baseline controllable allowance of €3.2 billion (2024 prices) over PR6, comprised of €3 billion in capex and €0.2 billion in controllable opex and a small allowance to account for input price pressures and future efficiencies.

This baseline allowance is €1 billion lower than the equivalent Draft Determination figure, reflecting a clearer understanding of what investment will be delivered through this allowance. The €3 billion capex allowance provides full funding (€2 billion) for the priority projects, each of which is associated with a delivery obligation, and reduced funding for other projects to allow the TAO to progress a portion of these. There are two other delivery obligations covering the other

¹¹ This excludes the costs that relate to the recovery of TAO revenues on behalf of ESBN via the TUoS charge, as well as PSO levy costs and FASS costs.

project categories, such that the delivery obligations collectively cover 74% of the baseline capex allowance.

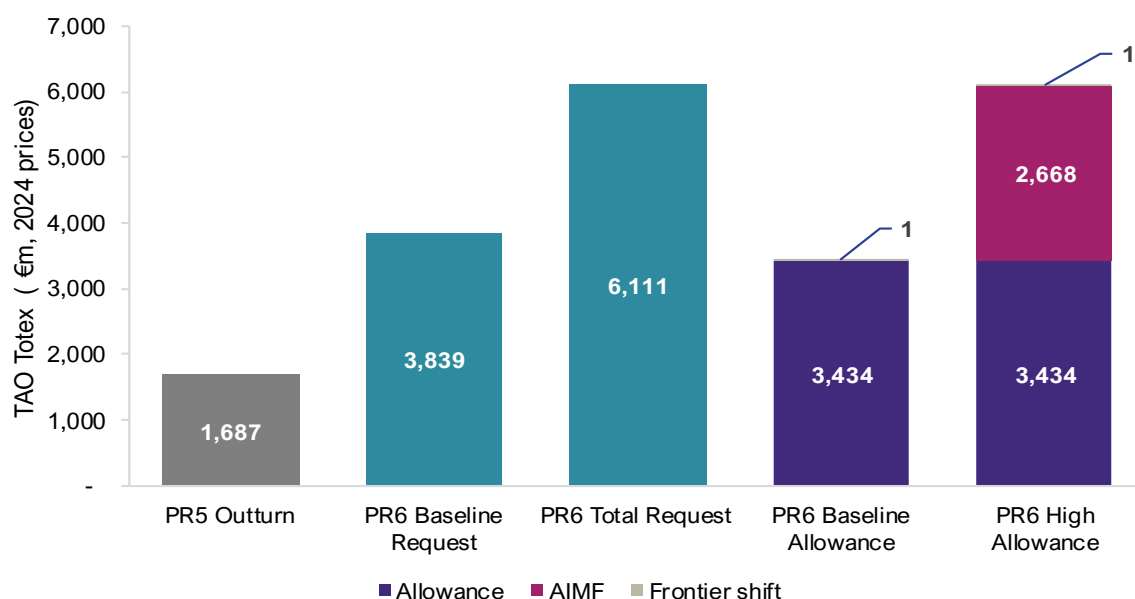
For the projects that have not been fully funded within the baseline allowance, there are reopeners to allow for additional funding as projects progress. Assuming all of this additional funding is utilised, the TAO's high allowance would be €5.9 billion for controllable elements (or €6.1 billion in total), broadly in line with the TAO's total request.

Non-Controllable Costs

Beyond the costs that are within the TAO's control, the CRU has provided an allowance of €0.2 billion for non-controllable opex, which will be treated as pass-through.

Figure 4 below shows a comparison of the PR6 allowances (including both controllable and non-controllable costs) against the TAO's requests and PR5 outturn expenditure. The total allowance is around twice as high as the €1.7 billion in expected outturn spend over PR5, to reflect the investment required to resolve network constraints and maintain security of supply.

Figure 4: Comparison of TAO PR5 Outturn, PR6 Request and PR6 Allowances (€m, 2024 prices)



3.2.3 DSO Allowance

Controllable Costs

For the controllable elements of the DSO's cost base, the CRU has provided a baseline allowance of €8.1 billion (2024 prices), made up of €5.9 billion in capex, €2.3 billion in controllable opex, and €19 million to account for frontier shift (future input price pressures and future efficiencies). Around a quarter of the baseline capex allowance of €5.9 billion is associated with specific delivery obligations related to network reinforcement activity and digital projects.

While the baseline allowance is lower than the DSO's baseline request of €9.5 billion, it is higher than the Draft Determination proposed allowance of €7.3 billion. There is also significant scope to increase the level of funding available through the AIMF, giving the DSO greater flexibility to undertake additional activity once there is greater certainty of need. The DSO has access to 16 reopeners, covering load and non-load related network activity as well as non-network activity and opex, and eleven volume drivers that will release additional funding if the volume of work is higher than assumed within the baseline.

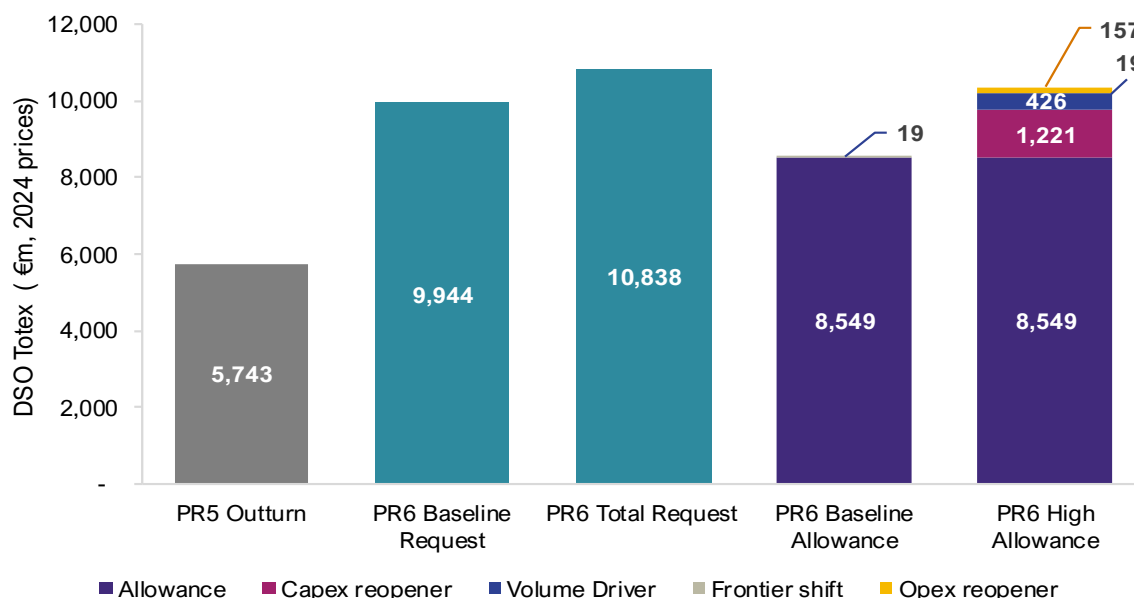
The high allowance, which covers all the additional funding available through re-openers and volume drivers, is €9.9 billion in total. This remains lower than the €10.4 billion requested by the DSO, as not all investment categories had been adequately justified.

Non-Controllable Costs

Beyond the costs that are within the DSO's control, the CRU has provided an allowance of €0.4 billion for non-controllable opex, which would be treated as pass-through.

Figure 5 below shows a comparison of the PR6 allowances (including both controllable and non-controllable costs) against the DSO's requests and PR5 outturn expenditure. Collectively, the baseline allowance is approximately 50% higher than expected outturn spend over PR5.

Figure 5: Comparison of DSO PR5 Outturn, PR6 Request and the Allowed Expenditure (€m, 2024 prices)



3.2.4 OAO Allowances

PR6 will set the first offshore price review. The PR6 period will see EirGrid, as OAO:

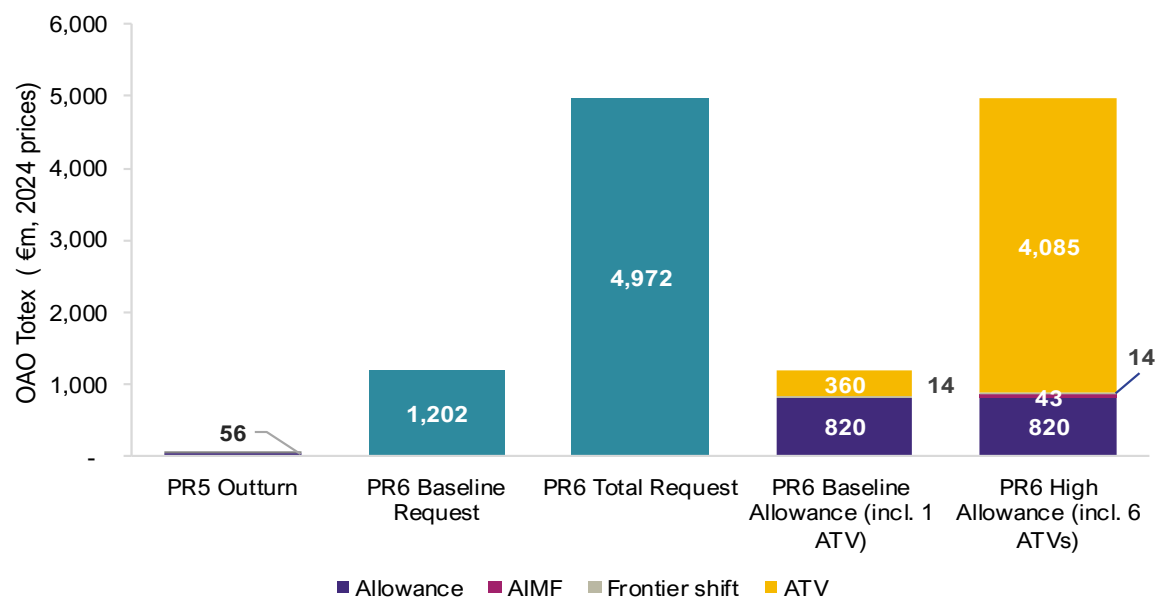
- Adopting a number of offshore transmission assets from offshore wind developers, related to Offshore Renewable Electricity Support Scheme (ORESS) 1 projects. This will be Phase 1 of EirGrid's offshore programme.
- Developing the capability to maintain those Phase 1 assets once they have been transferred over from developers, i.e. the OARP.
- Undertaking pre-construction activities related to Phase 2 of EirGrid's offshore programme. As part of Phase 2, EirGrid will design, request consent for and build offshore transmission assets under the South Coast (Tonn Nua) Programme following the ORESS2.1 auction that is expected to take place later this year.

As a result, under PR6, EirGrid will be required to finance a multi-billion-euro asset transfer programme from a limited starting asset base, as well as develop substantially different operational capabilities than it currently undertakes.

However, there is substantial uncertainty around the volume of asset transfers that will take place during PR6. The CRU has set the baseline allowance assuming one Phase 1 asset will be transferred to EirGrid during PR6. However, there are uncertainty mechanisms to unlock the full funding required if all six Phase 1 assets are transferred to EirGrid by the end of the PR6 period.

As shown in Figure 6, the baseline allowance for the OAO assuming one Phase 1 asset transfer is €1.2 billion, made up of €0.4 billion of capex associated with the Phase 1 asset transfer, €0.4 billion of other capex including Phase 2 expenditure, and €0.4 billion of opex plus an additional €14 million for the frontier shift. In the high scenario, we assume six asset transfers, resulting in an allowance of €5.0 billion. This differs from the high scenario referenced in the CRU's PR6 summary document (CRU2025193) which assumes the same allowed expenditure for offshore in both baseline and high cases, reflecting a less optimistic scenario where only one Phase 1 project transfer occurs in PR6.

Figure 6: Comparison of OAO PR5 Outturn, PR6 Request and the PR6 Allowance (€m, 2024 prices)



3.3 Financial Policy Framework

The financial policy framework is critical to the success of PR6 because it determines whether network companies can access the billions of euros in financing needed to deliver Ireland's energy transition. To attract the scale of private investment required to finance the step-change in capital investment, network companies must be able to offer investors returns that adequately compensate for the risks involved. If the financial framework does not provide sufficient returns, companies cannot raise the capital needed and critical infrastructure projects may be delayed or cancelled, ultimately harming customers. If the returns are set too high, customers pay more than necessary through their electricity network charges.

The CRU has therefore made several targeted changes to the financial policy framework to support the step increase in capital investment whilst ensuring customers receive value for money. These changes mostly relate to the allowed cost of capital (the weighted average cost of capital (WACC)) that network companies can earn on their capital investments.

Higher cost of capital for the DSO and TAO: For the DSO and TAO, the allowed cost of capital has increased from 3.80% in PR5 to the PR6 decision of 4.00%. The allowed cost of capital determines the return that network companies can earn on their investments, which affects their ability to attract the financing needed for their capital investments. This increase largely reflects current market conditions, particularly increases in government borrowing rates and overall market returns. However, the CRU has also changed how it assesses the relative riskiness of the DSO and TAO by focusing on comparable European energy networks rather than a broader set of companies. This updated approach, which better reflects the actual risks faced by ESNB, has helped to moderate the overall increase in the cost of capital that it is allowed to earn.

Separate cost of capital for the TSO: For the first time, the CRU has set a different cost of capital for EirGrid as the TSO, rather than using the same rate as the DSO and TAO. This recognises that EirGrid operates very differently – it owns few physical assets (making it "asset-light"), uses shorter-term borrowing, and will face increased scrutiny from credit rating agencies as its role expands as the OAO. Setting separate rates ensures that each company's specific circumstances are properly reflected in their allowed returns.

In setting the allowed cost of capital, the CRU has updated how it accounts for EirGrid's higher operational risks compared to asset-heavy companies like ESB Networks. Rather than adding a separate margin on top of revenues (as in PR5), these risks are now built directly into the cost of capital calculation, through the "beta", following the approach used by other regulators for similar system operators. The CRU has also adjusted the cost of borrowing assumptions to reflect EirGrid's shorter-term debt profile, though this has only resulted in small changes to the overall borrowing costs. Despite EirGrid's requests for additional premiums to reflect Irish market conditions and company size, the CRU found insufficient evidence to support these adjustments.

Bespoke offshore financial framework for the OAO: EirGrid's offshore programme requires a fundamentally different financial approach due to its unprecedented scale, complexity, and risk profile compared to traditional network investments. The CRU has designed a supportive framework that provides EirGrid with the financial certainty needed to attract billions in private investment whilst protecting customers from excessive costs.

The framework addresses three key challenges:

1. The programme involves two distinct investment phases with different risk characteristics – taking over existing offshore projects from developers (Phase 1) and building new transmission infrastructure from scratch (Phase 2). Therefore, unlike the single WACCs for transmission and distribution activities, the CRU considers that setting a separate WACC is justified given the circumstances of Phase 1 investment activities being developer-led investment. The number and the timing of Phase 1 ATV transfers in PR6 is also currently highly uncertain, and there are as a result, practical challenges with setting a single blended offshore WACC for PR6.
2. The offshore programme carries significantly higher investment risks than traditional onshore networks, including programme execution risks, the transition from an asset-light to asset-heavy business model, and operating under a new regulatory framework. To compensate investors for these additional risks and ensure the programme can attract necessary funding, the CRU has set a higher cost of capital for offshore activities compared to onshore network investments.
3. Given the uncertainty around EirGrid's borrowing costs during this major business transformation, the CRU has implemented a debt cost adjustment mechanism that allows EirGrid to recover its actual efficient borrowing costs. This provides additional financial certainty for both the company and investors as the offshore programme develops, reducing the risk that projects could be delayed due to financing difficulties.

Table 4 below summarises the allowed cost of capital in the PR6 Final Determination.

Table 4: WACC Comparisons: PR5, PR6 Company Proposals and the CRU PR6 WACC

	PR5	Company Proposed PR6	CRU PR6 Final Determination
TAO & DSO	3.80%	4.23%	4.00%
TSO	3.80%	4.89% ¹²	5.41%
OAo	N/A	4.60% for Phase 1 5.24% for Phase 2	4.51% (Developer-led investment) 5.12% (EirGrid-led investment)

Notes: The WACC values here are real and pre-tax. The TSO PR5 and Company Proposed PR6 WACCs are not directly comparable to the CRU PR6 Final Determination WACC, as the latter includes an upwards adjustment for higher operational risks, whereas this was previously captured as a separate margin.

3.4 Revenue Allowances and Cost Drivers

The changes to the cost allowances and associated financial policy framework means that the revenues the network companies are allowed to recover from network charges has also increased from PR5. While the cost allowances have increased materially from PR5, not all of this additional expenditure will be recovered from network charges in PR6 – the cost of the additional capex will be spread over several price review periods. As such, the increase in revenue allowances is less pronounced than the increase in cost allowances.

Table 5 below shows the total allowed revenues for PR6, compared to PR5 for each network company.

Table 5: Total Revenue Requirement for Each Network Company: PR5 vs PR6 (€m, 2024 prices)

	PR5 Final Determination (€m)	PR6 Final Determination Baseline (€m)	PR6 Final Determination High (€m)
DSO	5,433	7,466	7,914
TSO	1,824	4,026	4,175
TAO	1,539	2,105	2,398
OAo	N/A	523	798

Notes: (1) The PR5 figures are the unsmoothed revenue requirements set at the PR5 Final Determination. As such, they exclude any adjustments associated with the PR5 AIF. (2) The TSO PR6 revenue requirements include FASS costs but exclude the TAO payment. (3) The revenue requirements for both cases of PR6 include the frontier shift.

As can be seen in the table above, the allowed revenues have increased for each network company relative to the PR5 Final Determination. However, the most recent years of PR5 have

¹² 67th percentile of EirGrid's proposed range including aiming up of 30bps on the WACC.

seen a number of exceptional costs that were not originally envisaged when the PR5 revenue allowances were first set. As such, the impact on revenues when taking into account these exceptional costs is more limited. To support stakeholder understanding of what has driven the change in revenue allowances, we have split the change in revenue allowances into cost drivers. Further details on what each cost driver represents are provided in Appendix A.2.

Table 6 breaks down the PR6 Final Determination baseline revenue requirement into the various cost drivers.

Table 6: Breakdown of Revenue Requirement into Various Cost Drivers – PR6 Final Determination Baseline Scenario (€m, 2024 Prices)

	DSO	TSO	TAO	OAO
Better services for customers	557	-	-	-
Delivering decarbonised electricity	686	6	11	-
Secure and resilient networks and supplies	1,455	54	350	-
Security of supply, ancillary services and FASS	-	2,498	-	-
System planning costs	-	881	23	-
Offshore planning	-	-	-	520
Other operational costs and investments	1,098	221	280	-
Depreciation	2,498	419	625	-
Return	1,306	108	908	-
Incentives & adjustments	-193	-66	-43	-
Revenue smoothing adjustment	+69	+22	+13	-
Total	7,476	4,142	2,166	520

Notes: The totals in this table differ from the totals in Table 5 as they include additional incentives and adjustments included within the 2026 allowed revenues (e.g. adjustments to account for under-recovery of historic revenues).

Table 7 below shows the annual profile of revenues from 2024 to 2030.

Table 7: PR6 Annual Revenue Allowances, Baseline Scenario (€m, 2024 Prices)

	2024	2025	2026	2027	2028	2029	2030
Distribution	1,182	1,104	1,295	1,434	1,507	1,583	1,657
Transmission and Offshore	1,026	1,387	1,346	1,379	1,324	1,358	1,421

Notes: 2024-2026 allowances shown are based on the published allowances adjusted to be stated in 2024 prices. The 2024-2026 figures also include year-on-year adjustments to account for incentives, uncertainty mechanisms, reconciliations to account for over-/under-recovery of historic revenues, and reconciliations to account for non-controllable costs where outturn costs were higher or lower than forecast.

4. Impact on Domestic Customers

In this section, we present the estimated impact of the PR6 Final Determination on the network charges levied on domestic electricity customers, using an archetypical domestic customer as an example. In the following section (5) the same is presented for non-domestic archetypes. We also describe the key cost drivers that influence the impact on network charges. In this section we present all figures in nominal terms.

We present two scenarios to illustrate the estimated impact on consumers; one representing a **Baseline** that excludes the additional funding that is part of the AIMF and a **High** scenario that includes this additional funding. We compare these against the requests made by each network company, which are similarly split into Baseline and High illustrations.

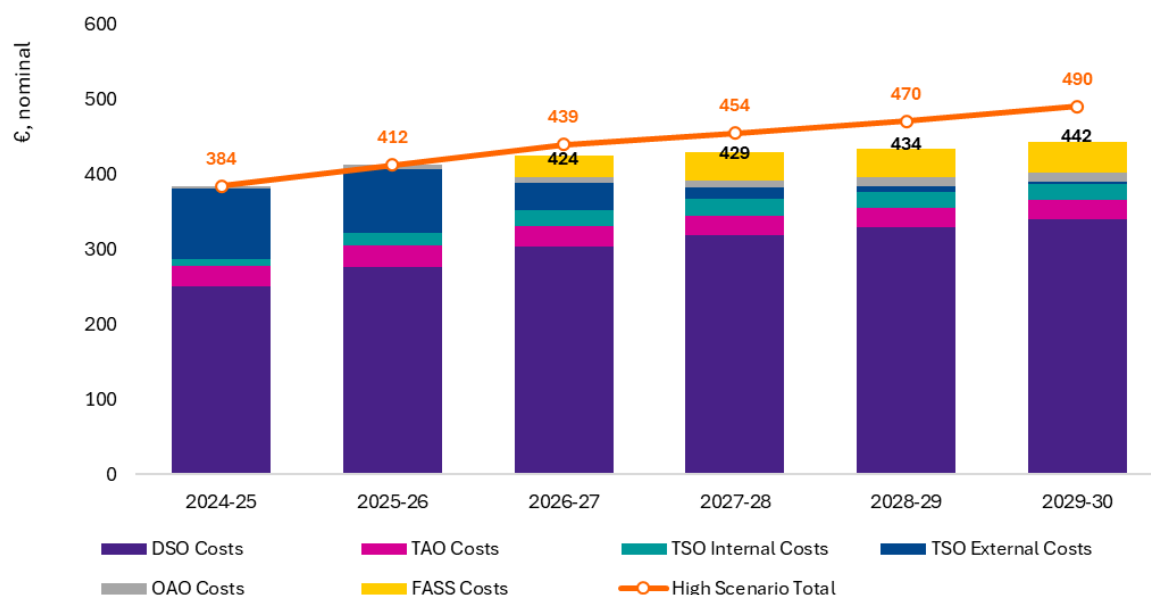
Further details on the assumptions we have used and our approach to modelling the estimated impact on customers, is presented in Appendix A: Methodology for Estimating Network Charge Impacts. Further details on the characteristics of the archetypical domestic customer are presented in A.1, while further details on each scenario are presented in A.3.

The analysis and figures presented here are an updated version for the Final Determination. Updates include updated figures to reflect the final PR6 decision, model revisions and the inclusion of further analysis to address common queries and themes raised by stakeholders.

4.1 Total Network Impact

Figure 7 below presents the estimated impact of the PR6 Final Determination Baseline on network charges for the archetypical domestic consumer, accounting for all network charges. The High scenario is layered on top.

Over the five-year period from the 2024-25 tariff year to the 2029-30 tariff year, we expect the network charges for the archetypical domestic customer to increase by 15% to 28% in nominal terms. Excluding the effect of inflation, this translates to an increase of between 6% and 17% on network charges.

Figure 7: PR6 Impact: Archetypical Domestic Customer (€, Nominal Values)


Notes: (1) While FASS costs will be recovered separately from DUoS and D-TUoS charges, current estimates have been included here for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) are recovered via D-TUoS charges. For information, the estimated FASS component of bills for domestic customers is presented in A.4. **(2)** 2024, 2025 and 2026 calculations are based on the published allowances and the modelling is intended to align with the published network charges up to 2025-26. For 2027 to 2030 the values are based on the PR6 revenue models and PR6 network charge impact modelling which, being forecasts, do not include k-factors or other adjustments that are only applied when the revenues for the specific year are being set.

Table 8 shows how this compares against the estimated impact based on the company asks.

Table 8: Domestic Customer Total Network Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	384	464	+81	+21%
Company Full Ask		496	+113	+29%
PR6 Baseline		442	+59	+15%
PR6 High		490	+106	+28%

Note: While FASS costs will be recovered separately from DUoS and D-TUoS charges, current estimates have been included here for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) are recovered via D-TUoS charges. Estimated FASS component of bills is presented in A.4 for information.

Considering the CRU PR6 allowances in the high scenario, there are several contributing factors which result in the estimated €106 net increase in network charges between 2024-25 and 2029-30. The largest factors contributing to this increase are as follows:

- Additional investment to deliver decarbonisation (+€53)
- Additional investment to deliver secure and resilient networks and supplies (+€46)
- Spending on the offshore programme (+€19)

These increases are partially offset by several decreasing factors, the most notable of which is security of supply, ancillary services and FASS (-€28).

The following sections detail how this impact relates to each element of the network (distribution, transmission and offshore).

4.2 Distribution Impact

Looking specifically at the distribution network, we estimate that the archetypical domestic customer will see an increase of between 36% and 47% in the distribution charges relating to their usage by the end of PR6.

Table 9: Domestic Customer Distribution Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	250	358	+108	+43%
Company Full Ask		371	+121	+48%
PR6 Baseline		339	+89	+36%
PR6 High		369	+118	+47%

Based on the PR6 allowances in the high scenario, the distribution charges which relate to an archetypical domestic customer are estimated to increase by €118 from 2024-25 to 2029-30. Most of this relates to increased investment in decarbonisation (+€53), higher investment to deliver secure and resilient networks and supplies (+€41), and other operational costs and investments (+€19). An estimated reduction in returns (-€25) partially counteracts the increases.

4.3 Transmission Impact

Looking specifically at the transmission network, we estimate that the archetypical domestic customer will see a decrease in the transmission charges relating to their usage by the end of PR6.

Table 10: Domestic Customer Transmission Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	130	92	-38	-29%
Company Full Ask		98	-32	-25%
PR6 Baseline		90	-40	-31%
PR6 High		99	-31	-24%

Note: While FASS costs will be recovered separately from DUoS and D-TUoS charges, current estimates have been included here for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) are recovered via D-TUoS charges. Estimated FASS component of bills is presented in A.4 for information.

Based on the PR6 allowances in the high scenario, in 2029-30 an estimated €31 net decrease from 2024-25 values is expected in the transmission charges relating to the archetypical domestic customer. The largest movement relates to less profiled spending on security of supply, ancillary services and FASS (-€28), followed by a reduction in incentives and adjustments (-€9), and other operational costs and investments (-€9). The largest increasing factor relates to depreciation (+€5).

4.4 Offshore Impact

The archetypical domestic customer is expected to see an increase in the offshore charges relating to their usage by the end of PR6.

Table 11: Domestic Customer Offshore Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	3	14	+11	+350%
Company Full Ask		27	+23	+731%
PR6 Baseline		13	+9	+292%
PR6 High		22	+19	+583%

Based on the PR6 allowances and a high scenario of 6 Phase 1 Asset Transfer Value (ATV) payments in PR6 compared to 1 ATV payment in the base scenario, offshore charges which relate to the archetypical domestic customer are estimated to be between €13 and €22 in 2029-30, an increase from €3 in 2024-25.

5. Impact on Non-Domestic Customers

This section describes the estimated impact of PR6 on non-domestic electricity customers (in nominal terms), using a series of archetypical customers of different consumption levels. Further details on the defining characteristics of these example customers are available in A.1.

As with our estimates of the impact on domestic customers, we present two scenarios; one representing a **Baseline** scenario that excludes the additional funding that is part of the AIMF and a **High** scenario that includes this additional funding. We compare this against the requests made by each network company, which are similarly split into Baseline and High illustrations.

5.1 Total Network Impact

Table 12 below presents the estimated impact of the PR6 Final Determination on network charges for the archetypical non-domestic electricity consumers.

Table 12: Non-Domestics Total Network Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	3,481	4,166	+684	+20%
	Company Full Ask		4,458	+977	+28%
	PR6 Baseline		3,967	+486	+14%
	PR6 High		4,402	+920	+26%
Medium (1)	Company Baseline Ask	95,070	107,059	+11,989	+13%
	Company Full Ask		115,990	+20,920	+22%
	PR6 Baseline		102,179	+7,109	+7%
	PR6 High		114,279	+19,209	+20%
Medium (2)	Company Baseline Ask	657,945	609,444	-48,501	-7%
	Company Full Ask		680,733	+22,788	+3%
	PR6 Baseline		584,789	-73,155	-11%
	PR6 High		666,739	+8,795	+1%
Large	Company Baseline Ask	1,527,840	1,451,819	-76,021	-5%
	Company Full Ask		1,610,244	+82,404	+5%
	PR6 Baseline		1,391,740	-136,100	-9%
	PR6 High		1,582,757	+54,918	+4%
XLEU	Company Baseline Ask	6,758,543	5,552,379	-1,206,164	-18%
	Company Full Ask		6,527,982	-230,561	-3%
	PR6 Baseline		5,379,773	-1,378,770	-20%
	PR6 High		6,351,624	-406,919	-6%

Note: While FASS costs will be recovered separately from DUoS and D-TUoS charges, current estimates have been included here for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) are recovered via D-TUoS charges. Estimated FASS component of bills is presented in A.4 for information.

Under the CRU's PR6 high scenario, network charges are expected to increase for most non-domestic customer archetypes. However, we observe from the table that the estimated impacts

vary significantly across different customer types. This is due to how network charges are structured and is discussed further in section 6.

To illustrate what is driving the estimated change in network charges over PR6 in the high scenario, we use the Medium (2) customer archetype as an example. For the Medium (2) customer, total network charges are expected to rise by €8,795 over the PR6 period in the high case, mainly driven by an increase in spending on offshore planning activities (+€63,531), decarbonisation initiatives (+€38,455) and investments in secure and resilient networks (+€36,826). However, the increases are partially offset by reductions, the largest of which are in security of supply, ancillary services and FASS charges (-€95,931) and other operational costs and investments (-€22,021).

The following sections explain how these changes relate to distribution, transmission and offshore network charges specifically.

5.2 Distribution Impact

It is estimated that the charges which relate to the distribution network usage of the archetypical non-domestic customers will increase over PR6.

Table 13: Non-Domestic Distribution Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	2,216	3,158	+941	+42%
	Company Full Ask		3,273	+1,057	+48%
	PR6 Baseline		2,990	+774	+35%
	PR6 High		3,249	+1,033	+47%
Medium (1)	Company Baseline Ask	49,876	71,056	+21,180	+42%
	Company Full Ask		73,646	+23,769	+48%
	PR6 Baseline		67,296	+17,420	+35%
	PR6 High		73,110	+23,233	+47%
Medium (2)	Company Baseline Ask	228,784	259,841	+31,056	+14%
	Company Full Ask		269,310	+40,525	+18%
	PR6 Baseline		246,091	+17,307	+8%
	PR6 High		267,350	+38,566	+17%
Large	Company Baseline Ask	605,971	688,225	+82,254	+14%
	Company Full Ask		713,305	+107,334	+18%
	PR6 Baseline		651,807	+45,836	+8%
	PR6 High		708,115	+102,144	+17%
XLEU¹³	Company Baseline Ask	812,296	922,506	+110,210	+14%
	Company Full Ask		956,123	+143,827	+18%
	PR6 Baseline		873,690	+61,395	+8%
	PR6 High		949,166	+136,870	+17%

Taking the small non-domestic archetypical customer as an example, distribution network charges are expected to rise by €1,033 between 2024-25 and 2029-30 under the PR6 high scenario. The largest drivers of this increase are investments in decarbonisation activities (+€469) and improvements to network security and resilience (+€363). The increases are partially offset by lower returns related to historic investments (-€220).

5.3 Transmission Impact

It is estimated that non-domestic customers will see a decrease in the transmission network charges associated with their usage by the end of PR6:

¹³ The customers in this archetype are DG10 customers and are charged for transmission (including offshore) only. These values represent the estimated amounts that would be charged to the TSO by the DSO for the archetypical customer, and are included for information purposes only.

Table 14: Non-Domestic Transmission Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	1,235	871	-364	-29%
	Company Full Ask		932	-303	-25%
	PR6 Baseline		857	-378	-31%
	PR6 High		944	-291	-24%
Medium (1)	Company Baseline Ask	44,103	31,100	-13,003	-29%
	Company Full Ask		33,280	-10,823	-25%
	PR6 Baseline		30,610	-13,493	-31%
	PR6 High		33,726	-10,377	-24%
Medium (2)	Company Baseline Ask	418,256	300,577	-117,679	-28%
	Company Full Ask		320,781	-97,475	-23%
	PR6 Baseline		295,975	-122,282	-29%
	PR6 High		324,955	-93,302	-22%
Large	Company Baseline Ask	900,061	665,542	-234,519	-26%
	Company Full Ask		715,656	-184,405	-20%
	PR6 Baseline		654,486	-245,576	-27%
	PR6 High		725,774	-174,288	-19%
XLEU	Company Baseline Ask	6,592,805	4,807,187	-1,785,618	-27%
	Company Full Ask		5,150,230	-1,442,575	-22%
	PR6 Baseline		4,730,376	-1,862,429	-28%
	PR6 High		5,220,221	-1,372,584	-21%

Note: While FASS costs will be recovered separately from DUoS and D-TUoS charges, current estimates have been included here for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) are recovered via D-TUoS charges. Estimated FASS component of bills is presented in A.4 for information.

For the medium (1) customer, transmission network charges are expected to decrease by €10,377 between 2024-25 and 2029-30 under the PR6 high scenario. The main driver of this reduction is lower security of supply, ancillary services and FASS charges (-€9,593), along with decreased incentives and adjustments (-€3,193) and other operational costs and investments (-€3,119). This reduction is partially offset by cost drivers which increase over the period, the largest of which are depreciation (+€1,549) and increased spending on secure and resilient networks (+€1,478).

5.4 Offshore Impact

It is estimated that non-domestic customers will see an increase in the offshore charges associated with their electricity usage by the end of PR6:

Table 15: Non-Domestics Offshore Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	31	137	+107	+350%
	Company Full Ask		254	+223	+731%
	PR6 Baseline		120	+89	+292%
	PR6 High		208	+178	+583%
Medium (1)	Company Baseline Ask	1,090	4,903	+3,812	+350%
	Company Full Ask		9,064	+7,974	+731%
	PR6 Baseline		4,272	+3,182	+292%
	PR6 High		7,443	+6,353	+583%
Medium (2)	Company Baseline Ask	10,904	49,026	+38,122	+350%
	Company Full Ask		90,642	+79,738	+731%
	PR6 Baseline		42,723	+31,820	+292%
	PR6 High		74,434	+63,531	+583%
Large	Company Baseline Ask	21,808	98,052	+76,244	+350%
	Company Full Ask		181,283	+159,476	+731%
	PR6 Baseline		85,447	+63,639	+292%
	PR6 High		148,869	+127,061	+583%
XLEU	Company Baseline Ask	165,738	745,192	+579,454	+350%
	Company Full Ask		1,377,752	+1,212,014	+731%
	PR6 Baseline		649,397	+483,659	+292%
	PR6 High		1,131,403	+965,665	+583%

To take an example, based on the PR6 allowances and a high case scenario assuming 6 Phase 1 ATV transfers during PR6, offshore charges which relate to the large archetypical consumer are estimated to be €85,447 (baseline scenario) in 2029-30, an increase from €21,808 in 2024-25.

6. Further Information on Network Charges

In this section, we discuss the uncertainty around the customer impact estimates presented in this paper and also provide results of some sensitivity testing around those impacts. We also provide more general commentary regarding differences in customer impacts across the different archetypes.

6.1 Sensitivity and Uncertainty

It is important to highlight that beyond the two scenarios presented in the previous sections (baseline and high), there are several other areas of uncertainty around the impacts on network charges. Beyond the decisions made as part of PR6, we discuss below some of the other key assumptions that could drive changes in future network charges.

Inflation

The PR6 impacts on network charges have been presented in nominal terms and so, include an estimate of future inflation. However, as network charges are linked to outturn inflation, higher or lower inflation in the economy than is assumed in our forecast will result in higher or lower network charges. The inflation forecast used in this paper is in line with the forecast included in the published PR6 Final Determination Revenue Models.

To give an indication of the impact of the inflation forecasts on the network charges, we estimate that the network charge will increase by around €59 between 2024-25 and 2029-30 under the baseline scenario when the impact of inflation is included (see Section 4.1). However, excluding the impact of inflation, the network charge is expected to grow by €23 over the same period.

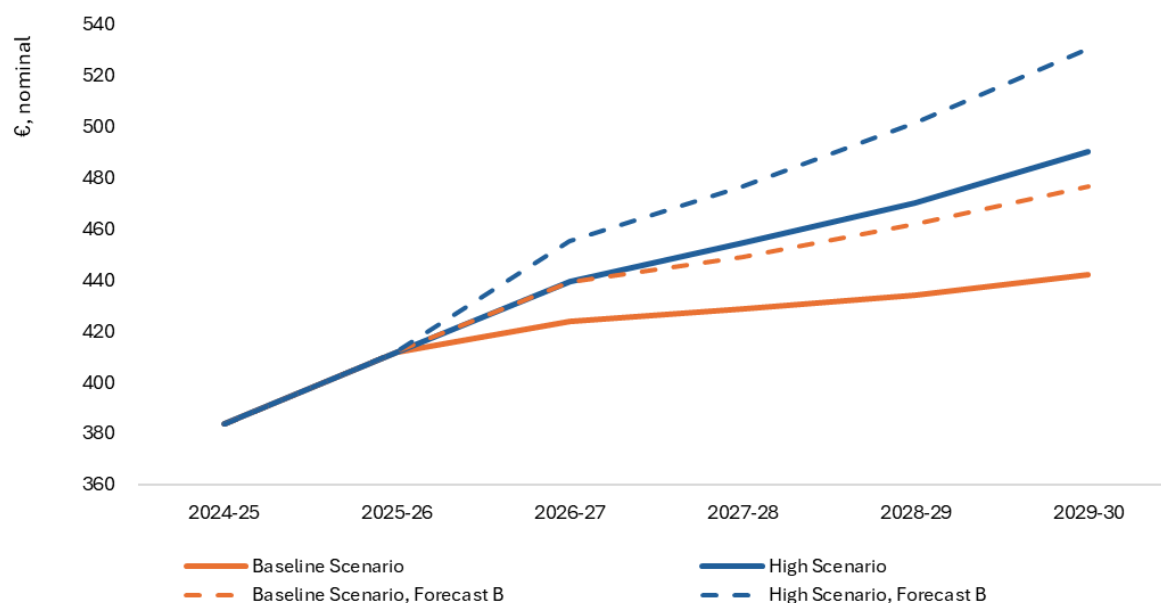
Demand and Other Tariff Input Parameters

The estimates of future network charges presented in this paper use forecasts of several parameters that are used as inputs in the annual transmission and distribution tariff setting process. These include network company forecasts of customer numbers, total system capacity and total delivered energy. However, the forecasts of these tariff input parameters may differ from those in the future annual tariff setting processes, which may result in a different network charge. For example, if customer numbers are lower than has been assumed in this paper, then the network company revenue allowance will be recovered over fewer customers, increasing the impact of network charges on an individual customer. The converse would also be true.

While these input parameters are updated annually by the network companies as part of the tariff setting process, the customer impact estimates presented in this paper have been derived using the same forecasted input parameters as were used in the modelling for the Draft Determination. This aids comparability between the Draft Determination and the Final Determination.

On 26 August 2025 the CRU published the distribution and transmission allowed revenues for 2026 (CRU2025118 and CRU2025119). As part of the Final Determination, the CRU has also assessed the impact of updating the forecasted input parameters. Compared to the forecasts used in the estimates presented earlier in this paper, this includes lower overall energy demand and lower growth in customer numbers. This sensitivity is presented as forecast B in Figure 8 below.

Figure 8: Impact of “Forecast B” Input Parameters on Network Charge Estimate for Domestic Archetype (€, Nominal)



Under forecast B (adjusted parameters) the estimated network charges for a domestic customer in the baseline scenario would be €477 in 2029-30 in nominal terms (€436 in real 2024 terms).

As can be seen, changes in the forecasted inputs can have a strong impact on the estimated PR6 network charges. The updated parameters form part of the annual tariff setting process. The number of forecasted inputs involved in the modelling - and the impact that these forecasts have on the estimates - should be borne in mind when considering this PR6 impact analysis.

Non-Controllable Costs

PR6 includes provisions for the network companies to pass through costs that are outside of their control, such as costs incurred by the TSO to maintain the stability of the electricity grid (i.e. ancillary services) or to maintain the security of Ireland’s electricity supply. If outturn non-controllable costs differ from what has been assumed when setting PR6 allowances, there will be a consequential impact on network charges. In PR5, such non-controllable costs were responsible for large differences between the revenue allowances set at the start of PR5 and the actual revenue allowances used when setting annual tariffs.

Offshore Costs

Another source of uncertainty for PR6 arises from the evolution of costs and financing associated with EirGrid's emerging role as the OAO. The CRU's analysis under PR6 highlights some key areas of uncertainty:

- **Multi-phase investment programme:** Offshore grid infrastructure development, spanning Phase 1 (developer-led asset transfer) through Phase 2 (TSO-led build) and will require multi-billion-euro investment within PR6 and PR7. Phase 1 includes large ATV payments to developers, and Phase 2 covers substantial construction costs (e.g., Tonn Nua), both of which are highly sensitive to cost overruns and schedule delays.
- **Regulatory flex mechanisms:** To manage cost risks, the CRU has introduced enhanced investment gateways, liquidity allowances, and exceptional-events triggers. The effectiveness and timeliness of these mechanisms in responding to actual cost pressures will shape final charge outcomes.

6.2 Impacts Across Customer Types

It can be observed from Table 1 that the estimated PR6 impacts on network charges vary significantly across different customer types. This is due to how network costs are recovered (further details in Section 7.4).

As has been shown in previous sections, distribution charges are increasing for all archetypical customers while transmission charges are decreasing for all archetypical customers between the 2024-25 and 2029-30 network charges estimates. This is because:

- **Distribution Charge Increases:** much of the PR6 investment driving increases in network charges is on the distribution network (see Table 7).
- **Transmission Charge Decreases:** some key drivers would be the reduction in security of supply allowances from 2024-25 (*circa* €0.3 billion allowance in 2025 allowed revenues (CRU202482)), down to zero by the end of PR6 and the reduction in Clean Energy Package costs (*circa* €0.1 billion in 2025 allowed revenues (CRU202482)), down to €0.02 billion profiled for 2030. These have a significant impact on the trend as they are part of the TSO's external costs, which are all recovered through D-TUoS tariffs. Transmission cost items which are classified as TSO internal costs or TAO costs are not entirely recovered through D-TUoS only¹⁴, which also means that the impact of increasing allowances in these categories is slightly muted when it comes to the D-TUoS charges.

¹⁴ They are also recovered partially through G-TUoS.

These increases and decreases impact the various customer types differently, depending on to what extent (if any) they are exposed to distribution or transmission network charges.

For domestic customers, the distribution charges generally form a larger part of their network charges than the transmission charges. For example, in 2024-25 the archetypical domestic customer's network charges were €384, of which €250 (or 65%) related to distribution, whereas €133¹⁵ (or 35%) related to transmission. For 2029-30 their estimated network charges in the baseline scenario are €442 (a 15% increase from 2024-25), of which €339 (or 77%) relates to distribution and €103¹⁶ (or 23%) relates to transmission. We can see that the movement is strongly influenced by the increasing distribution charges.

If we consider the medium non-domestic (2) customer archetype, the assessed transmission charges generally form a larger part of their network charges than the distribution charges. For example, in 2024-25 the archetypical domestic customer's network charges were €657,945, of which €228,784 (or 35%) related to distribution, whereas €429,160¹⁵ (or 65%) related to transmission. This customer is more exposed to changes in the transmission charges than the distribution charges. However, transmission charges are decreasing over the period. Their estimated total 2029-30 network charges in the baseline scenario are €584,789 (an 11% decrease from 2024-25), of which €246,091 (or 42%) relates to distribution, and €338,698¹⁶ (or 58%) relates to transmission.

To provide additional context, we have examined the changes in network charges using 2020-21 as the baseline year. This was the first tariff year of PR5 and was unaffected by the exceptional cost items that arose during PR5. From this starting point, the data shows a consistent upward trend in charges across all customer archetypes through to 2029-30. Noticeably, the increases are not uniform: medium non-domestic (2), large non-domestic, and XLEU archetypical customers experience significantly higher percentage increases in network charges compared to smaller usage categories. This demonstrates that larger customers are also experiencing rising costs—they are, in fact, seeing the most pronounced increases over the period shown.

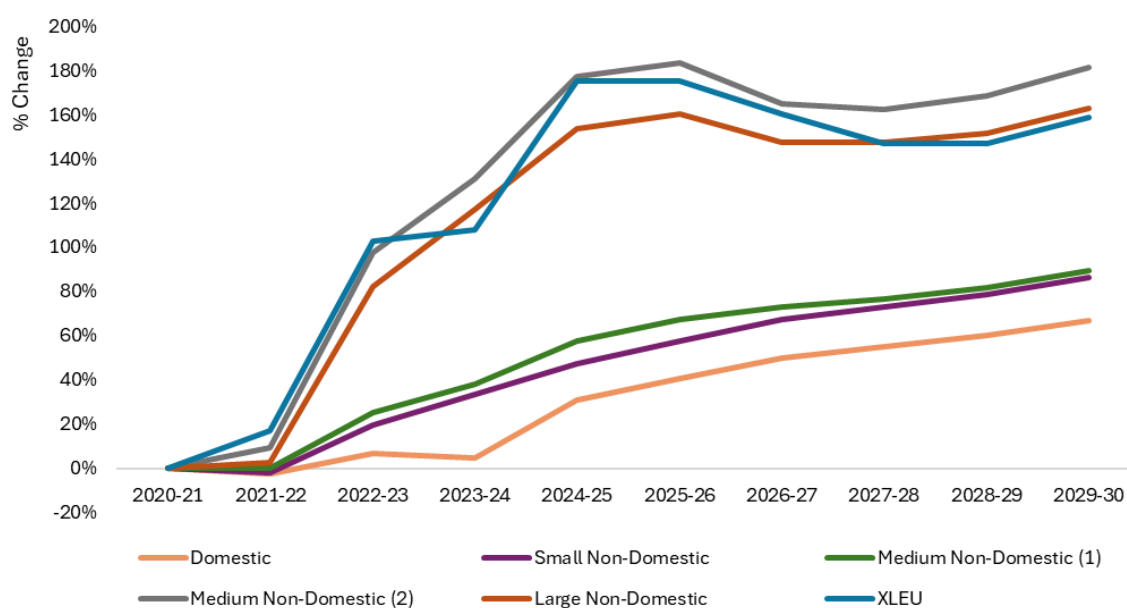
Details provided below in Table 16 and Figure 9.

¹⁵ Including Offshore.

¹⁶ Including FASS and Offshore.

Table 16: For Information Purposes: Table 1 Restated with Different Base Year

Example Customer	Baseline Scenario			High Scenario	
	2020-21, €	2029-30, €	Change from 2020-21	2029-30, €	Change from 2020-21
Domestic	293	442	+149 (+51%)	490	+197 (+67%)
Small non-domestic	2,362	3,967	+1,605 (+68%)	4,402	+2,040 (+86%)
Medium non-domestic (1)	60,357	102,179	+41,821 (+69%)	114,279	+53,922 (+89%)
Medium non-domestic (2)	237,138	584,789	+347,651 (+147%)	666,739	+429,601 (+181%)
Large non-domestic	602,671	1,391,740	+789,069 (+131%)	1,582,757	+980,086 (+163%)
XLEU	2,454,335	5,379,773	+2,925,438 (+119%)	6,351,624	+3,897,289 (+159%)

Figure 9: Percentage Change in Estimated Network Charges vs 2020-21 Network Charges, All Archetypes (Based on High Scenario, Nominal Values)


7. Related Topics

In order to provide further context, in this section we present details of some CRU workstreams (some within PR6 and some separate to PR6) which are relevant to the wider discussion of consumer impacts.

7.1 Customer Protection Measures

Separately to PR6, the CRU has published an updated decision on additional customer protection measures for household electricity and gas customers 2025/26 in CRU2025125. The measures seek to protect customers from the worst effects of high energy prices, while retaining an open, competitive retail energy market. Some of these measures include increased emergency credit available to customers, lowered PAYG debt recovery ratios, and extended time for customers to repay debt on repayment plans.

7.2 Vulnerable Customer Incentive

A new incentive included in PR6 is the Vulnerable Customer Incentive. This incentive reflects the need for ESB Networks to support vulnerable customers by providing enhanced and targeted support. More details are available in the PR6 Regulatory Framework paper CRU2025197.

7.3 2025-26 Annual Revenues and Tariffs

Since the PR6 Draft Determination, the CRU has published the 2025-26 annual revenues and tariffs for Distribution and Transmission ([CRU2025118](#) and [CRU2025119](#) respectively). Customer impacts are included in the appendices of both papers.

7.4 Tariff Structures and Tariff Structure Review

Separately to PR6, on 10 September 2025 the CRU published [CRU/2025/120](#), which marks the re-commencement of its review of the structure of electricity network tariffs. The underlying role of network tariffs is to provide for recovery of the costs necessary to support the development, operation and maintenance of our electricity networks by ESB Networks and EirGrid. How network tariffs are structured determines how these costs are allocated across network users and can influence their behaviour.

The estimated impacts of PR6 on network charges provided in the previous sections of this paper are modelled based on the current tariff structures. PR6 does not alter the tariff structures.

8. Conclusion and Next Steps

The estimated impact of the CRU PR6 Final Determination on network charges which relate to electricity consumers has been illustrated in this paper, along with the impact on the network companies. The information provided in this paper aims to ensure that the CRU's PR6 assessment is transparent and allows for targeted stakeholder understanding and engagement.

As part of PR7, the CRU hopes to look back at these estimates from the PR6 Final Determination. While certain assumptions have been made in the modelling, it should still be possible to make a general analysis looking back over the period. This would be a valuable exercise as it would draw out elements which changed over the period and might also help improve any future consumer impact modelling in this area.

Appendix A: Methodology for Estimating Network Charge Impacts

This section provides a summary of the approach taken to calculate the financial impact of PR6 on archetypical electricity customers.

A.1 Summary of Approach

Our estimates of the impact of the PR6 Final Determination on customer network charges largely replicates analysis undertaken by the respective network companies and presented to the CRU:

- For DUoS charges, we have replicated ESBN's methodology of increasing each tariff linearly to meet the revised revenue allowance, after accounting for growth in customer numbers and growth in electricity demand / network capacity. The estimates for customer numbers, electricity demand and network capacity were all provided to us by ESBN.

In our modelling, we have included the impact of the correction of the historic under-recovery of revenues for large energy users

- For D-TUoS charges, we have replicated EirGrid's methodology of splitting the costs recovered via Generator Transmission Use of System (G-TUoS) and D-TUoS, with the latter split further into revenue recovered from system services charges, network transfer charges, and capacity charges. Finally, we have used adjustment factors and demand/capacity assumptions aligned with those used by EirGrid to convert these into tariff estimates.

For offshore, we assume the majority of revenues will be recovered from offshore developers via the Offshore Generator Transmission Use of System (OG-TUoS) charge, with the remainder recovered via D-TUoS charges, in line with CRU policy. Where offshore costs will be recovered from D-TUoS charges, we model this as recovered from system services charges¹⁷.

This analysis assumes no change to the tariff structure (see section 7.4 for more details) and assumes fixed consumption characteristics. In other words, we assume that electricity demand

¹⁷ A new 'Offshore Grid Charge' is to be introduced which will be part of D-TUoS charges once implemented.

for an archetypical customer stays fixed and as such, we exclude the effect of changing demand for that customer (e.g. increased demand from the transition to EVs or heat pumps or reduced demand from improved energy efficiency). This allows us to isolate the effect of key decisions made in the PR6 Final Determination from other drivers of the typical electricity network charges.

For the PR6 Final Determination network charge estimates for 2025-26, we use the revenue allowances and tariffs as set during the 2025-26 tariff setting process. However, when presenting the Company Ask network charge estimates, we do not use the actual 2025-26 tariffs, instead using the implied tariffs as per the business plan submissions.

In Table 17 below, we provide details on the consumer archetypes we use in this paper:

Table 17: Archetypical Customers

Example Customer	Annual Usage (KWh)	MIC (kVA)	Example Further Details	Tariff Type	DG Number
Domestic	3,682	N/A	Urban Residential	24 Hour	1
Small non-domestic	35,000	N/A	Bar/Local Shop	24 Hour	5
Medium non-domestic (1)	1,250,000	350	Hotel	Dual Tariff	6
Medium non-domestic (2)	12,500,000	2,825	University	TOU	7
Large non-domestic	25,000,000	10,000	Factory/ Manufacturing (Large Pharma)	TOU	7
XLEU	190,000,000	44,000	XLEU	TOU	10 (note)

Note: For DG10 customers, ESB Networks recovers its DG10 DUoS network costs directly from EirGrid (TSO).

A.2 Summary of Cost Drivers

In order to provide insight into the causes of the impacts described in this paper, related costs have been grouped into categories, and the categories which have the greatest impact on charges over the period are highlighted. The cost drivers are intended to give a general idea of what factors are driving movements in the charges relating to electricity consumers.

The cost drivers which were considered in the analysis are below:

- **Better services for customers:** Includes a range of costs such as those relating to meter reading, customer relations, area operations and call centres.
- **Decarbonisation:** This cost driver category includes additional opex and investment needed to support the decarbonisation of the energy system. For additional capital

investment related to decarbonisation, this will be partially recovered through the depreciation and return building blocks, with the remainder recovered over future price reviews.

- **Secure and resilient networks and supplies:** This category includes additional opex and investment needed to support the delivery of a secure and resilient energy system. This includes spending on maintenance, system control and costs associated with EirGrid's interconnector investments.
- **Security of supply, ancillary services and FASS:** This cost driver includes costs such as those relating to the security of supply project, Dublin security of supply, DS3 system services, ancillary services and FASS (current estimates). As some of these costs are reducing over PR6 (e.g. security of supply and DS3 system services), while the FASS tariff is due to start during the period, the movements within this category from 2024-25 to 2029-30 counteract each other to some degree. The security of supply project alone was a major element of the 2024 and 2025 TSO allowances,^{18, 19} and so the reduction in this cost item during PR6 has a strong effect on the figures presented for this category.
- **System planning costs:** This category includes routine costs associated with EirGrid's operational activity, such as staff costs, IT costs, professional services and contractors.
- **Offshore planning:** This cost driver is the sole driver for the OAO customer impacts shown in this paper. Offshore costs relating to demand customers which have been forecast in this analysis include all OAO opex (which includes the OARP) and the operation and maintenance costs of Phase 1 and Phase 2 assets) and the return on Tonn Nua from the point at which spend is incurred until Tonn Nua becomes live (at which point it starts being recovered from OG-TUoS charges). Across all scenarios we have assumed that there are not any cost overruns in Phase 1 projects.
- **Other operational costs and investments:** Includes a range of costs such as those relating to Article 13.7, Clean Energy Package, rates and insurance.
- **Depreciation:** Only includes depreciation relating to capital expenditure before PR6, as well as PR6 TSO capital expenditure. Depreciation on PR6 capital expenditures is allocated to the relevant cost driver, for instance depreciation during PR6 on PR6 capital expenditure on network reinforcements is included under the "Decarbonisation" cost driver (as this expenditure advances electrification).

¹⁸ [CRU2023104 - Electricity Transmission Network Allowed Revenues for 2024 And Demand Transmission Use of System \(D-TUoS\) Tariffs 2023/24](#)

¹⁹ [CRU202482 - Electricity Transmission Network Allowed Revenues for 2025 And Demand Transmission Use of System \(D-TUoS\) Tariffs 2024/25](#)

- **Return:** Only includes returns relating to investments before PR6 and relating to TSO PR6 investments. Similar to the depreciation cost driver, returns during PR6 relating to PR6 expenditure are allocated to the relevant cost drivers.
- **Incentives and adjustments:** Includes AIF and other PR5 adjustments.
- **Revenue smoothing adjustment:** As the 2026 revenue allowance was fixed as part of the tariff setting process, any additional allowance for 2026 provided as part of the Final Determination will be recovered from the 2027 to 2030 revenue allowances.

A.3 Scenario Details

Table 18 below details key parameters that are used in the four scenarios presented in this paper. Where data spans more than one scenario it is the same in all the scenarios it spans.

Table 18: Scenario Further Details (2024 Values)

Network Company	Company Baseline Ask	Company Full Ask	Final Determination Baseline	Final Determination High
DSO	Baseline only	AIMF included	Baseline only	AIMF included
	WACC (real, pre-tax): 4.23%		WACC (real, pre-tax): 4.00%	
	Opex: €3,020m		Opex: €2,703 (incl. frontier shift of €19m)	Opex: €2,860m (incl. frontier shift of €19m)
	Gross Capex: €6,923m	Gross Capex: €7,818m	Gross Capex: €5,865m	Gross Capex: €7,511m
OAO	Separate nominal WACCs for Phase 1 and Phase 2, with additional liquidity building block and Cost of Debt true-up.		Developer-led investment WACC (real, pre-tax): 4.51% EirGrid-led investment WACC (pre-tax): 5.12%	
	Opex: €409m	Opex: €453m	Opex: €402m (incl. frontier shift of €14m)	Opex: €445m (incl. frontier shift of €14m)
	Gross Capex: €794m	Gross Capex: €4,518m	Gross Capex: €792m	Gross Capex: €4,517m
	Tonn Nua (Phase 2 project) estimated to cost €1.55bn, of which €363m incurred in PR6.			
	One Phase 1 asset transferred to EirGrid during PR6: Oriel Wind Park (delivery date Q2 2029, ATV: €360m).	Six Phase 1 assets transferred to EirGrid during PR6 in line with EirGrid business plan submission (6 ATV: €4.01bn).	One Phase 1 asset transferred to EirGrid during PR6: Oriel Wind Park (delivery date Q2 2029, ATV: €360m).	Six Phase 1 assets transferred to EirGrid during PR6 in line with EirGrid business plan submission (6 ATV: €4.01bn).
TAO	Baseline only	AIMF included	Baseline only	AIMF included

	WACC (real, pre-tax): 4.23%		WACC (real, pre-tax): 4.00%	
	Opex: €427m		Opex: €420m (incl. frontier shift of €1m)	
	Gross Capex: €3,171m	Gross Capex: €5,705m	Gross Capex: €4,017m	Gross Capex: €5,676m
TSO	WACC (real, pre-tax): 4.89% + Operational gearing margin		WACC (real, pre-tax): 5.41% ²⁰	
	Controllable Opex: €950m		Controllable Opex: €867m (incl. frontier shift of €30m)	Controllable Opex: €950m (incl. frontier shift of €30m)
	Non-Controllable Opex ²¹ : €1,616m			
	Gross Capex: €877m		Gross Capex: €717m	Gross Capex: €856m
	FASS: €1,568m			
	Exceptional Items: €745m			

Notes: (1) The company opex (company baseline and full ask scenarios) does not include a frontier shift. **(2)** The Final Determination baseline and high scenarios include a frontier shift. The frontier shift includes RPEs (increase in allowance) and OE (decrease in allowance). For all network companies, except the TSO, the frontier shift is applied to opex. For the TSO, it is applied only to the controllable opex.

²⁰ CEPA have proposed including the operational gearing margin within the WACC estimate. A like-for-like comparison with EirGrid's proposed WACC (i.e. excluding the operational gearing margin adjustment) would be ~3.84%.

²¹ Excluding FASS and TAO payment.

A.4 FASS Estimated Values

While FASS costs will be recovered separately from D-TUoS charges, current indicative estimates have been included in the above analysis for consistency with the 2024-25 tariff where DS3 system services costs (the precursor to FASS) were recovered via D-TUoS charges. For completeness, the values included in the analysis in this paper for indicative FASS estimates are provided in Table 19 below. The values are the same across all four scenarios. These are indicative impacts only.

Table 19: FASS Customer Impact Values by Archetype (€, Nominal Values)

Example Customer	2026-27	2027-28	2028-29	2029-30
Domestic	28	38	39	40
Small non-domestic	270	358	371	378
Medium non-domestic (1)	9,630	12,773	13,265	13,517
Medium non-domestic (2)	96,298	127,733	132,653	135,168
Large non-domestic	192,597	255,465	265,306	270,337
XLEU	1,463,736	1,941,535	2,016,327	2,054,558