



An Coimisiún
um Rialáil Fónas
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 Draft 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) Draft Determination proposals will impact both electricity customers and network companies. It should be read alongside the PR6 Draft Determination papers for distribution (CRU202587), transmission (CRU202588) and offshore (CRU202589). The purpose of this impact analysis note is to provide transparency on the CRU's proposals and enable stakeholders to understand and engage effectively with the key changes being introduced. The paper addresses two main questions:

1. **Impact on network companies:** How will the PR6 Draft Determination proposals affect the operations, responsibilities and financial position of EirGrid and ESB Networks?
2. **Impact on customer bills:** How will the proposed revenue allowances affect electricity 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 Draft 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 27 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 approximately double its PR5 allowance (€1.4 billion baseline), the TAO receives three times its previous allowance (€4.4 billion baseline), and the Distribution System Operator (DSO) receives a 40% increase (€7.7 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 Draft 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 bills under both the baseline allowance and a high scenario (where all the additional funding available through the AIMF is utilised and 6 Phase 1 offshore projects transfer to EirGrid during PR6).

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

Example Customer	Baseline Scenario			High Scenario	
	2024-25, €	2029-30, €	Change	2029-30, €	Change
Domestic	374	404	+29 (+8%)	454	+80 (+21%)
Small non-domestic	3,392	3,636	+243 (+7%)	4,094	+702 (+21%)
Medium non-domestic (1)	91,887	94,207	+2,320 (+3%)	106,793	+14,906 (+16%)
Medium non-domestic (2)	643,515	616,724	-26,791 (-4%)	708,104	+64,590 (+10%)
Large non-domestic	1,517,530	1,485,862	-31,668 (-2%)	1,698,601	+181,071 (+12%)
XLEU	6,479,356	5,294,345	-1,185,011 (-18%)	6,255,655	-223,701 (-3%)

The CRU’s PR6 Draft Determination proposals aim 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 proposed through the Draft 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 Draft Determination proposals also aim 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.

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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
DD	Draft Determination
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
TOU	Time of Use
TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
XLEU	Extra Large Energy User

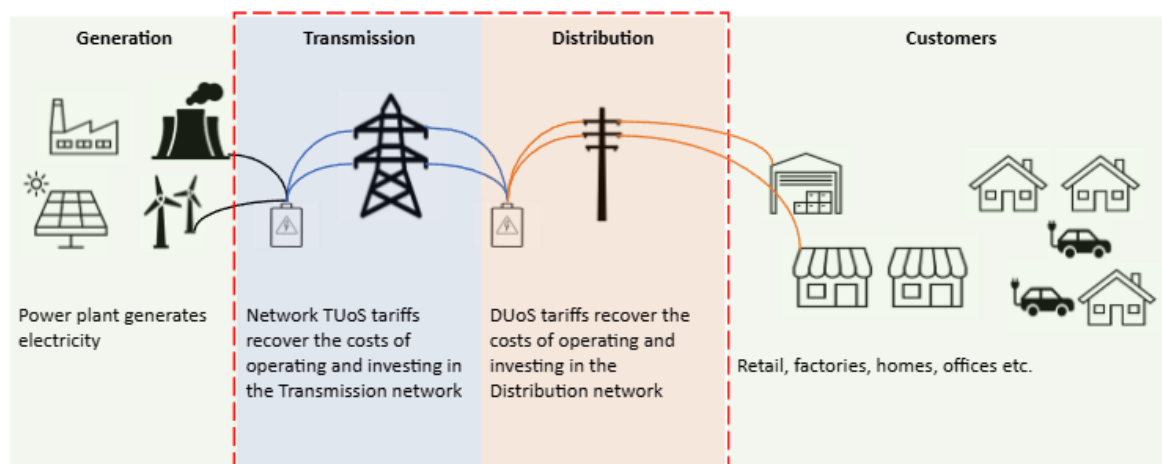
1. Introduction

This paper outlines the potential impact of the PR6 Draft Determination proposals. 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 proposed 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 Draft 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 bills in 2029-30 (the final tariff year entirely in PR6) relative to customer bills in 2024-25 (representing current

bills).¹ We present the impact on different types of customers, such as domestic vs 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 bills.

We present the network company cost and revenue values (e.g. PR6 network company asks and CRU proposed revenues) in 2024 monies, unless stated otherwise, to ensure consistency across PR6 papers. However, we present the estimates on consumer bills in nominal terms, unless otherwise stated, to provide a more realistic portrayal of potential future costs for electricity customers. As we have made several assumptions and simplifications in the analysis, and continue to refine and assess the modelling approach in advance of the Final Determination, the Price Review Six Impact Analysis figures should be considered as indicative current estimates only. 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 1 (Introduction)** outlines the purpose of this impact analysis note.
- **Section 2 (Background to the PR6 Draft Determination)** provides the context underpinning PR6 and summarises the key features of the PR6 Draft Determination.
- **Section 3 (Impact on Companies)** presents our view of the impact of the PR6 Draft Determination on the network companies, EirGrid and ESBN.
- **Section 4 (Impact on Domestic Customers)** outlines our emerging view of the PR6 impact on domestic customers.
- **Section 5 (Impact on Non-Domestic Customers)** outlines our emerging view of the PR6 impact on non-domestic customers.
- **Section 6 (Conclusion and Next Steps)** concludes and outlines future plans for this assessment.
- **Appendix A Methodology for Estimating Bill Impacts** provides a summary of the methodology used to estimate the impact on customers.

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](#)) whereas the PR6 Draft Determination information is currently the best information for estimating the 2029-30 tariff year charges.

2. Background to the PR6 Draft 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 Draft 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 (OAO).
- **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 comprise three 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.²
- Future Arrangements for System Services (FASS) charges³, which relate to the transmission system and will provide revenues for the TSO. This is a new charge (separate to TUoS) which is due to begin during PR6 and current estimates are included in this analysis for completeness. FASS replaces DS3 System Services (which is funded through the D-TUoS charges). For reference, FASS charges are delineated in A.4.

These charges are levied on electricity suppliers,^{4, 5} 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.

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 around customer interruptions on the distribution network and renewable energy integration targets on the transmission system. Experience with 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

² More details on the offshore tariff treatment can be found in the Price Review Six Offshore Draft Determination Paper (CRU202589).

³ [SEM-25-007 - All-Island System Services Supplier Charge](#)

⁴ For DG10 customers, ESNB bills the DG10 DUoS network costs directly from EirGrid (TSO).

⁵ Some of the very large customers act as their own suppliers.

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),⁶ three overarching outcomes that it expects electricity network companies to deliver throughout PR6:

- **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.

⁶ [CRU202427 PR6 Strategy Paper](#)

- **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 value of EirGrid's TSO Regulated Asset Base is forecast to be less than €40 million by the end of PR5 in 2025 but could exceed €5 billion by 2030 due to offshore infrastructure requirements.

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 Draft Determination

The CRU has developed a regulatory package for the Draft Determination that aims to meet the strategic objectives for PR6 described above:

- **Increased investment allowances:** To deliver the infrastructure needed for a decarbonised, secure and resilient energy system, there has been an over 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 27 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 proposed, 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, unlocking 1,940 MVA of additional capacity to maintain security of electricity supply and reduce costly constraints on the transmission network, plus a further 750 MVA of capacity specifically for connecting renewable energy sources through the North South 400 kV interconnector.
- **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 35 ultra-high voltage and offshore connections are expected to be energised 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 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 create additional capacity of 1.1 GW and 1.5 GW at 38 kV and medium voltage respectively across the distribution network nationwide, with specific delivery obligations to ensure measurable capacity improvements are achieved.
- **Comprehensive pole replacement strategy** of up to 50,000 poles⁷ 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 €0.8 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.

⁷ This includes 45,725 MV pole replacements and 4,550 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.

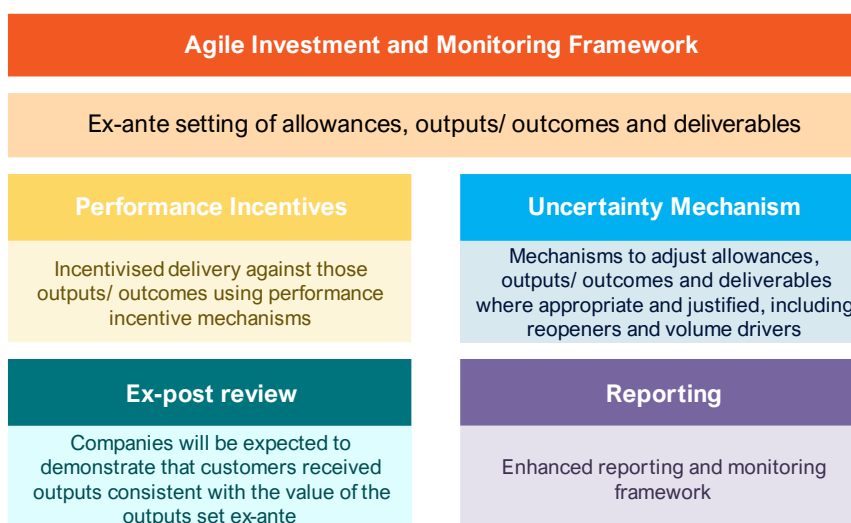
To help companies manage these uncertainties while ensuring strong performance, the CRU has developed a regulatory framework that provides network companies with clear funding commitments and specific output obligations. This is complemented by a suite of flexibility mechanisms that can adjust cost allowances 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.⁸
- **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.

⁸ 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 controls	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 proposed 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 that network companies must monitor and report on, 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 Licensees

	DSO	TSO	TAO
Overall package of incentives	<p>A total of 14 incentives, with 1 incentive retired:</p> <ul style="list-style-type: none"> 11 incentives retained from PR5 with amendments 3 new incentives 	<p>A total of 11 incentives:</p> <ul style="list-style-type: none"> 8 incentives retained from PR5 with amendments 1 new incentive 2 joint TSO/TAO incentives, with new metrics 	<p>A total of 4 incentives:</p> <ul style="list-style-type: none"> 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	<p>+€72m / -€65m (+1.80% / -1.63%)</p>	<p>+€32m / -€17m (+26.8% / -13.4%)</p>	<p>+€22m / -€22m (+1.00% / -1.00%)</p>
Key areas of focus	<p>Reliability (interruptions, unplanned outages), customer service (satisfaction scores, complaint resolution), vulnerable customer support, and connection delivery for both generation and demand customers.</p>	<p>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.</p>	<p>Infrastructure and project delivery (delivery of new and uprated overhead lines, new underground cable and new substations)</p>

The revised incentive framework provides several improvements for the network companies. Setting targets in advance 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.

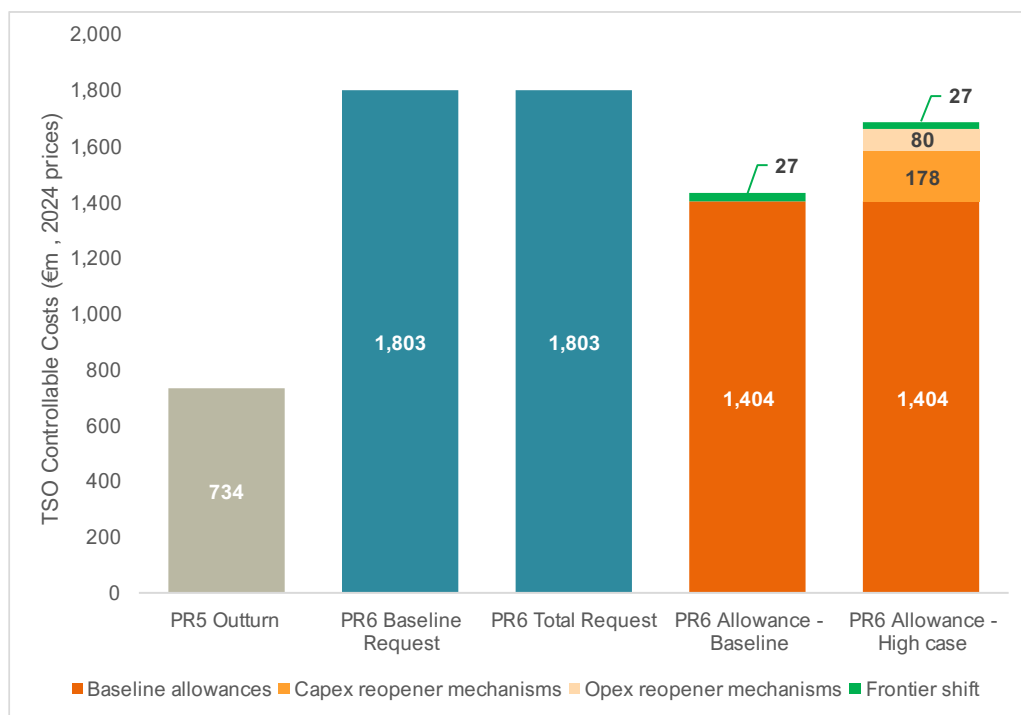
A key evolution from PR5 is the upfront inclusion of adjustments for input price pressures (referred to as real price effects (RPEs)) and year-on-year productivity improvements (referred to as ongoing efficiency (OE)) within the controllable operating expenditure (opex) cost allowances. Given the scale 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 Draft Determination cost allowances include a frontier shift for both the baseline and high scenario, but the company asks do not.

3.2.1 TSO Allowance

For controllable elements of the TSO’s cost base, the CRU has provided the TSO with a baseline allowance of approximately €1.40 billion (2024 prices) over PR6, which represents a doubling of the allowance relative to expected outturn spend in PR5, as shown in Figure 3. This covers €660 million of capital expenditure (capex) and €744 million of controllable opex with an additional €27 million for the frontier shift.⁹ This higher allowance reflects the increased complexity and scale of system operation required to support Ireland’s decarbonisation ambitions.

Figure 3: Comparison of TSO PR5 Outturn, PR6 Request and the Allowed Expenditure (€m, 2024 prices)



Within this baseline controllable allowance of €1.40 billion, 21% of the capex is ring-fenced through specific delivery obligations covering priority network projects¹⁰ and the development of

⁹ The frontier shift includes RPEs (increase in allowance) and OE (decrease in allowance) and is applied to controllable opex only.

¹⁰ For more details, please refer to the TAO-TSO 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, only 50% funding has been allowed for other projects, subject to reopener applications.

The TSO has access to eight 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 €1.66 billion – which is approximately 8% lower than the TSO's PR6 request.

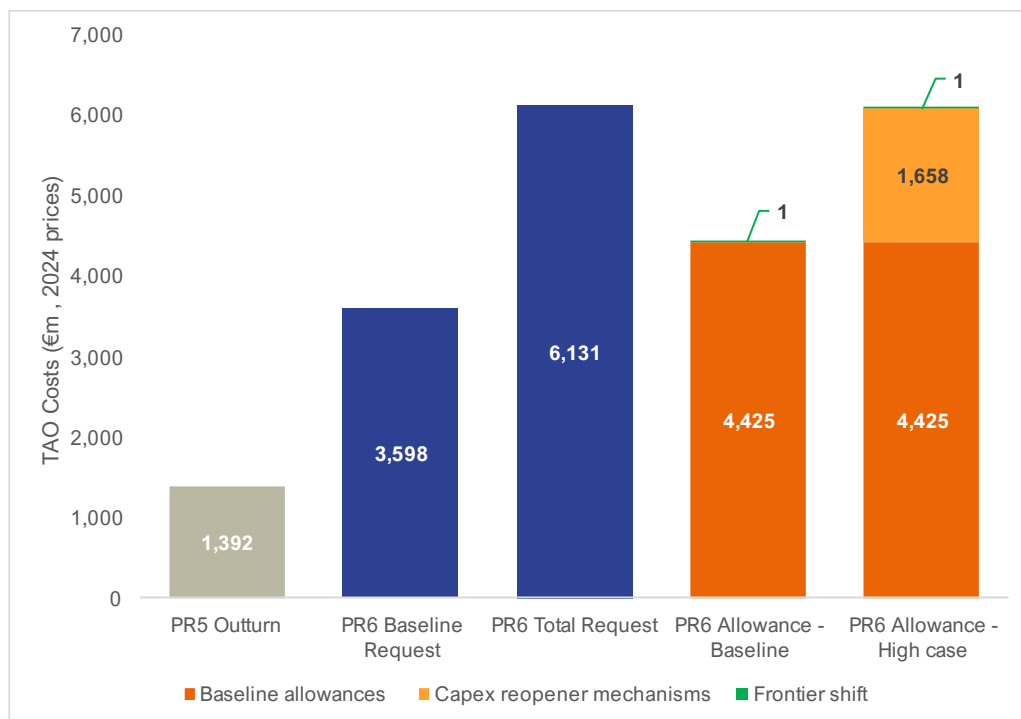
Beyond the controllable allowance, the TSO is expected to spend €745 million over PR6 on exceptional cost items mostly related to the Security of Supply programme, and a further €366 million on non-controllable costs.¹¹ These costs will be treated as pass-through.

3.2.2 TAO Allowance

For the TAO, the CRU has provided a baseline controllable allowance of €4.2 billion (2024 prices) over PR6, comprised of €4 billion in capex and €0.2 billion in controllable opex. This is three times as high as the €1.4 billion in expected outturn spend over PR5, to reflect the investment required to resolve network constraints and maintain security of supply, as shown in Figure 4. The allowance only includes a frontier shift of €1 million. 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 would be treated as pass-through.

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.

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



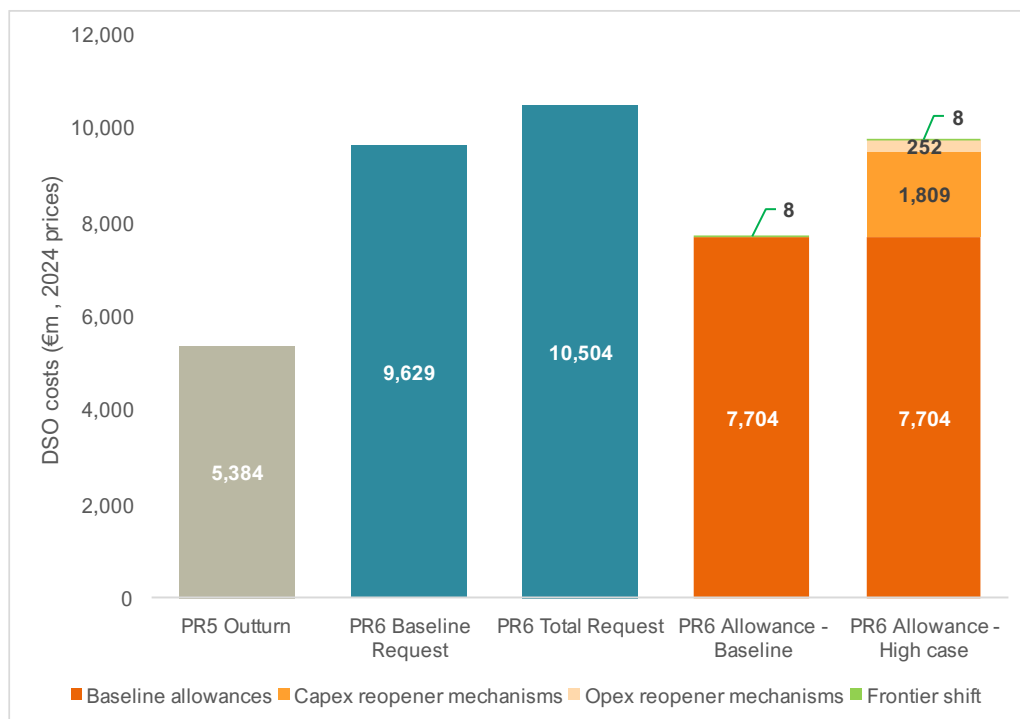
The baseline allowance provides full funding for priority projects, and reduced funding for other projects to allow the TAO to progress a portion of these. Of the €4 billion capex allowance, €2.9 billion relates to investment in the 29 priority network projects, each of which is associated with a delivery obligation. There are two other delivery obligations covering the other project categories, such that the delivery obligations collectively cover 87% 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.

3.2.3 DSO Allowance

For the controllable elements of the DSO’s cost base, the CRU has provided a baseline allowance of €7.7 billion (2024 prices), made up of €5.2 billion in capex, €2.5 billion in controllable opex, and an €8 million frontier shift. Collectively, this is approximately 35% higher than expected outturn spend over PR5, as shown in Figure 5. About a fifth of the baseline capex allowance of €5.2 billion is associated with specific delivery obligations related to network reinforcement activity and digital projects. 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: Comparison of DSO PR5 Outturn, PR6 Request and the Allowed Expenditure (€m, 2024 prices)



While the baseline allowance is materially lower than the DSO’s baseline request of €9.6 billion, there is a 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 eleven re-openers, covering load and non-load related network activity as well as non-network activity, and nine volume drivers (e.g. timber overhead under planned maintenance) 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 €9.8 billion in total (including the €0.4 billion of non-controllable opex). This remains lower than the €10.5 billion requested by the DSO, due to insufficient justification for some investment categories at this stage.

3.2.4 OAO Allowances

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

- Adopting a number of offshore transmission assets from offshore wind developer, 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 Offshore Asset Readiness Programme (OARP).

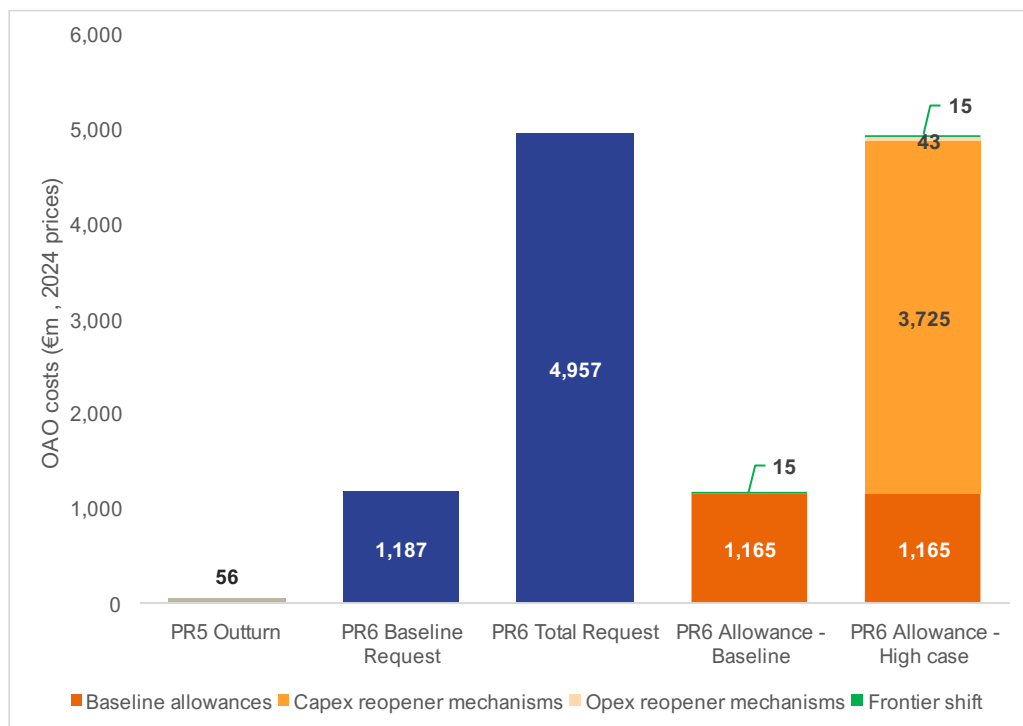
- Undertaking pre-construction activities related to Phase 2 of EirGrid’s offshore programme. As part of Phase 2, EirGrid will design, consent and build offshore transmission assets under the South Coast (Tonn Nua) Programme following the ORESS2.1 auction that is expected to take place later this year.

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 implied 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 €15 million for the frontier shift. In the high scenario, we assume six asset transfers, resulting in an implied allowance of €4.9 billion. This differs from the high scenario referenced in the CRU’s PR6 summary document (CRU202586) 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 Allowed Expenditure (€m, 2024 prices)



3.3 Financial Policy Framework

The financial policy framework is critical to PR6's success because it determines whether network companies can access the billions of euros in financing needed to deliver Ireland's energy transition. To attract this 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 bills.

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 slightly from 3.80% in PR5 to a PR6 Draft Determination proposal of 3.85%. 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 ESBN, 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. First, 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). Rather than setting separate cost of capital rates for each phase as EirGrid initially proposed, the CRU has established a single rate that reflects the programme's overall risk profile. This approach is more consistent with standard regulatory practice and aligns with how EirGrid will actually finance these investments.

Second, 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.

Third, 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 Draft Determination.

Table 4: Comparison of the Company Proposals and the CRU WACC Proposals for PR6

	PR5	Company Proposed PR6	CRU PR6 Draft Determination
TAO & DSO	3.80%	4.23%	3.85%
TSO	3.80%	4.89%	5.23%
OAO	N/A	4.84%	4.58%

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 Draft 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 revenue allowances have increased materially from PR5 allowances. Table 5 below shows the total allowed revenues for PR6, compared to PR5 for each of the licensee. As noted above, in contrast to the PR6 summary document, which assumes 1 ATV transfer in both baseline and high cases, Table 5 assumes 6 Phase 1 offshore ATV payments occur during PR6 for the purposes of illustrating the impact on customer bills if a more optimistic timeline for Phase 1 construction and operation were achieved than in the baseline.

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

	PR5 Final Determination (€m)	PR6 Draft Determination Baseline (€m)	PR6 Draft Determination High (€m)
DSO	5,433	6,935	7,503
TSO	1,824	3,956	4,119
TAO	1,539	2,079	2,269
OAO	N/A	482	690

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 substantially increased for each licensee relative to the PR5 Final Determination. However, the most recent years of PR5 have 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 a lot 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 Draft Determination baseline revenue requirement into the various cost drivers.

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

	DSO	TSO	TAO	OAo
Better services for customers	520	0	0	0
Delivering decarbonised electricity	567	6	14	0
Secure and resilient networks and supplies	1,292	35	391	0
Security of supply, ancillary services and FASS	0	2,455	0	0
System planning costs	0	819	0	0
Offshore planning	0	0	0	482
Other operational costs and investments	1,050	110	279	0
Depreciation	2,374	403	542	0
Return	1,223	99	887	0
Incentives & adjustments	-90	30	-34	0
Total	6,935	3,956	2,079	482

4. Impact on Domestic Customers

In this section, we present the estimated impact of the PR6 Draft Determination on the network charges levied on domestic electricity customers, using an archetypical domestic customer as an example. 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 **Draft Determination Baseline** that excludes the additional funding that is part of the AIMF and a **Draft Determination 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.

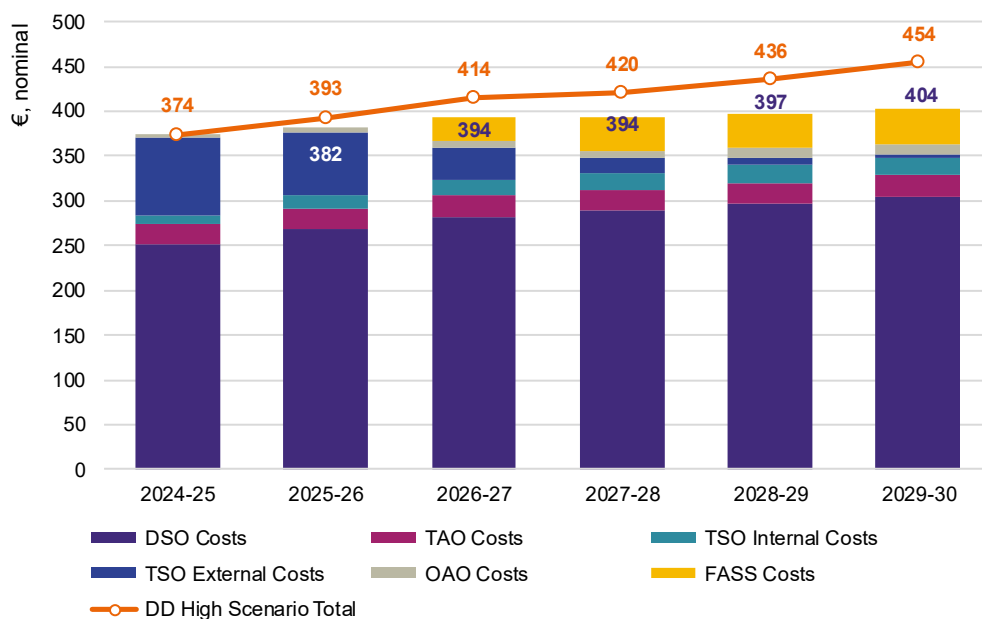
Further details on the assumptions we have used and our approach to modelling the estimated impact on customers, is presented in Appendix A Methodology for Estimating Bill Impacts. Further details on the characteristics of the archetypical domestic customer are presented in A.1, while further details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

4.1 Total Network Impact

Figure 7 below presents the estimated impact of the Draft Determination Baseline on bills for the archetypical domestic consumer, accounting for all network charges. The Draft Determination 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 typical network bill for domestic customers to increase by between 8% and 21% in nominal terms. Excluding the effect of inflation, this translates to a bill impact of between a 4% reduction and an 8% increase.

Figure 7: PR6 Draft Determination Impact for Domestic Customers (€, Nominal Values)



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. We separately present the estimated FASS component of bills for domestic customers in A.4.

Table 7 shows how this compares against the estimated impact based on the company asks.

Table 7: Domestic Customer Total Network Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	374	458	+84	+22%
Company Full Ask		496	+122	+33%
DD Baseline		404	+29	+8%
DD High		454	+80	+21%

Considering the CRU Draft Determination proposed allowance figures in the high scenario, there are several contributing factors which result in the estimated €80 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 (+€46)
- Additional investment to deliver secure and resilient networks and supplies (+€41)
- Spending on the offshore programme (+€21)

These increases are partially offset by several decreasing factors, the most notable of which is security of supply, ancillary services and FASS (-€23).

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 22% and 35% in the distribution charges relating to their usage by the end of PR6.

Table 8: Domestic Customer Distribution Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	250	360	+109	+44%
Company Full Ask		372	+122	+49%
DD Baseline		305	+54	+22%
DD High		337	+87	+35%

Based on the allowances proposed in the Draft Determination high scenario, the distribution charges which relate to an archetypical domestic customer are estimated to increase by €87 from 2024-25 to 2029-30. Most of this relates to increased investment in decarbonisation (+€46), higher investment to deliver secure and resilient networks and supplies (+€36), and other operational costs and investments (+€18). An estimated reduction in returns (-€28) is the largest factor partially counteracting 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 9: Domestic Customer Transmission Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	121	91	-29	-24%
Company Full Ask		97	-24	-20%
DD Baseline		87	-34	-28%
DD High		93	-28	-23%

Based on the allowances proposed in the Draft Determination high scenario, in 2029-30 an estimated €28 net decrease from 2024-25 values is expected in the transmission charges relating to the archetypical domestic customer. The largest movement relates to less anticipated spending on security of supply, ancillary services and FASS (-€23), followed by a reduction in incentives and adjustments (-€9), and other operational costs and investments (-€8). The largest increasing factor relates to investment in secure and resilient networks and supplies (+€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 10: Domestic Customer Offshore Impact (Nominal Values)

PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Company Baseline Ask	3	7	+4	+117%
Company Full Ask		26	+23	+779%
DD Baseline		12	+9	+301%
DD High		24	+21	+685%

Based on the allowances proposed in the Draft Determination and a high scenario of 6 Phase 1 ATV payments in PR6, offshore charges which relate to the archetypical domestic customer are estimated to be between €12 and €24 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 **Draft Determination Baseline** that excludes the additional funding that is part of the AIMF and a **Draft Determination 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 11 below presents the estimated impact of the Draft Determination Baseline on bills for the archetypical non-domestic electricity consumers, accounting for all network charges.

Table 11: Non-Domestics Total Network Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	3,392	4,116	+724	+21%
	Company Full Ask		4,468	+1,076	+32%
	DD Baseline		3,636	+243	+7%
	DD High		4,094	+702	+21%
Medium (1)	Company Baseline Ask	91,887	104,931	+13,044	+14%
	Company Full Ask		116,057	+24,171	+26%
	DD Baseline		94,207	+2,320	+3%
	DD High		106,793	+14,906	+16%
Medium (2)	Company Baseline Ask	643,515	664,858	+21,343	+3%
	Company Full Ask		763,275	+119,760	+19%
	DD Baseline		616,724	-26,791	-4%
	DD High		708,104	+64,590	+10%
Large	Company Baseline Ask	1,517,530	1,620,145	+102,615	+7%
	Company Full Ask		1,836,884	+319,354	+21%
	DD Baseline		1,485,862	-31,668	-2%
	DD High		1,698,601	+181,071	+12%
XLEU	Company Baseline Ask	6,479,356	5,273,075	-1,206,280	-19%
	Company Full Ask		6,622,614	143,258	+2%
	DD Baseline		5,294,345	-1,185,011	-18%
	DD High		6,255,655	-223,701	-3%

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 presented separately in A.4.

Under the CRU's PR6 Draft Determination proposals, in the high case, network charges are expected to increase for almost all non-domestic customers. However, we observe from the table that the estimated bill impacts vary significantly across different customer types. This is due to how network charges are structured. Non-domestic customers with lower electricity consumption will see proportionately larger bill increases, whilst very large energy users may actually experience bill reductions during PR6.

As we show in subsequent sections, this difference occurs because much of the investment driving bill increases is on the distribution network, which affects smaller users more heavily through distribution charges. In contrast, large energy users are primarily exposed to transmission charges, which are expected to decrease over PR6, offsetting the impact of higher distribution costs.

Looking at the XLEU archetypical customer specifically, we estimate that the network charge will reduce by between 3% and 18% over PR6. However, most of this relates to a reversal of recent increases in transmission charges – over PR5 (between 2020-21 and 2024-25), the archetypical XLEU customer experienced a 167% increase in network charges, compared with a 35% increase for domestic customers.

To illustrate what is driving the estimated change in bills over PR6 in the high case, we use the Medium (2) Customer archetype as an example. For the Medium (2) customer, total network charges are expected to rise by €64,590 over the PR6 period in the high case, mainly driven by an increase in spending on offshore planning activities (+€69,902), investments in secure and resilient networks (+€51,536), and decarbonisation initiatives (+€42,776). However, these increases are partially offset by reductions, the largest of which are in security of supply, ancillary services and FASS charges (-€77,415) and incentives and other adjustments (-€20,067).

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 archetypical non-domestic customers will see an increase in the charges which relate to the distribution network over PR6.

Table 12: Non-Domestic Distribution Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	2,216	3,185	+969	+44%
	Company Full Ask		3,295	+1,079	+49%
	DD Baseline		2,698	+482	+22%
	DD High		2,985	+769	+35%
Medium (1)	Company Baseline Ask	49,876	71,669	+21,792	+44%
	Company Full Ask		74,152	+24,275	+49%
	DD Baseline		60,706	+10,830	+22%
	DD High		67,169	+17,292	+35%
Medium (2)	Company Baseline Ask	228,784	328,794	+100,009	+44%
	Company Full Ask		340,185	+111,401	+49%
	DD Baseline		278,502	+49,717	+22%
	DD High		308,150	+79,365	+35%
Large	Company Baseline Ask	605,971	870,856	+264,886	+44%
	Company Full Ask		901,028	+295,058	+49%
	DD Baseline		737,651	+131,681	+22%
	DD High		816,178	+210,207	+35%
XLEU¹²	Company Baseline Ask	812,296	1,167,307	+355,011	+44%
	Company Full Ask		1,207,750	+395,454	+49%
	DD Baseline		988,757	+176,462	+22%
	DD High		1,094,015	+281,719	+35%

Taking the small non-domestic archetypical customer as an example, distribution network charges are expected to rise by €769 between 2024-25 and 2029-30 under the PR6 Draft Determination high scenario. The largest drivers of this increase are investments in decarbonisation activities (+€409) and improvements to network security and resilience (+€316). The increases are partially offset by decreasing factors, most notably lower returns related to historic investments (-€248).

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:

¹² The customers in this archetype are DG10 customers and are charged by the TSO (rather than the DSO). These values represent the estimated relevant amount charged to the TSO by the DSO for these customers.

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

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	1,148	869	-278	-24%
	Company Full Ask		922	-226	-20%
	DD Baseline		823	-324	-28%
	DD High		885	-263	-23%
Medium (1)	Company Baseline Ask	40,989	31,045	-9,945	-24%
	Company Full Ask		32,930	-8,060	-20%
	DD Baseline		29,403	-11,586	-28%
	DD High		31,613	-9,377	-23%
Medium (2)	Company Baseline Ask	404,521	313,893	-90,629	-22%
	Company Full Ask		333,332	-71,189	-18%
	DD Baseline		297,250	-107,271	-27%
	DD High		319,843	-84,678	-21%
Large	Company Baseline Ask	891,141	704,945	-186,196	-21%
	Company Full Ask		756,340	-134,801	-15%
	DD Baseline		666,267	-224,873	-25%
	DD High		722,200	-168,941	-19%
XLEU	Company Baseline Ask	6,324,176	4,936,065	-1,388,111	-22%
	Company Full Ask		5,258,295	-1,065,881	-17%
	DD Baseline		4,671,579	-1,652,597	-26%
	DD High		5,037,959	-1,286,216	-20%

For the medium (1) customer, transmission network charges are expected to decrease by €9,377 between 2024-25 and 2029-30 under the PR6 Draft Determination high scenario. The main driver of this reduction is lower security of supply, ancillary services and FASS charges (-€7,741), along with decreased incentives and adjustments (-€2,942) and other operational costs and investments (-€2,839). This reduction is partially offset by cost drivers which increase over the period, the largest of which is increased spending on secure and resilient networks (+€1,774).

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 14: Non-Domestics Offshore Impact (Nominal Values)

Example Customer	PR6 Revenue Scenario	2024-25 (€)	2029-30 (€)	Change (€)	Change (%)
Small	Company Baseline Ask	29	62	+33	+117%
	Company Full Ask		251	+223	+779%
	DD Baseline		115	+86	+301%
	DD High		224	+196	+685%
Medium (1)	Company Baseline Ask	1,021	2,217	+1,196	+117%
	Company Full Ask		8,976	+7,955	+779%
	DD Baseline		4,097	+3,076	+301%
	DD High		8,011	+6,990	+685%
Medium (2)	Company Baseline Ask	10,209	22,172	+11,963	+117%
	Company Full Ask		89,758	+79,549	+779%
	DD Baseline		40,971	+30,762	+301%
	DD High		80,112	+69,902	+685%
Large	Company Baseline Ask	20,418	44,344	+23,925	+117%
	Company Full Ask		179,516	+159,097	+779%
	DD Baseline		81,943	+61,524	+301%
	DD High		160,223	+139,805	+685%
XLEU	Company Baseline Ask	155,180	337,011	+181,830	+117%
	Company Full Ask		1,364,319	+1,209,139	+779%
	DD Baseline		622,766	+467,585	+301%
	DD High		1,217,695	+1,062,515	+685%

To take an example, based on the allowances proposed in the Draft Determination 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 €81,943 (baseline scenario) in 2029-30, an increase from €20,418 in 2024-25.

6. Conclusion and Next Steps

The emerging impact of the CRU PR6 Draft Determination on network charges which relate to electricity consumers has been illustrated in this paper, along with the impact of the Draft Determination 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.

The CRU will continue to refine and assess the consumer impact modelling for the PR6 Final Determination.

As part of PR7, the CRU hopes to look back at the estimates from the Final Determination version of this paper. While certain assumptions and simplifications 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 Bill 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 Draft Determination on customer bills 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 excluded the impact of the correction of the historic under-recovery of revenues for large energy users, to allow for a more like-for-like comparison of bills.

- For D-TUoS charges, we have replicated EirGrid's methodology of estimating how the revenue allowance would be split into 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 assume this will be recovered from system services charges.

This analysis assumes no change to the tariff setting methodology and assumes fixed consumption characteristics. In other words, we assume that electricity demand for an archetypical customer stays fixed and as such, we exclude the effect of changing demand (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 Draft Determination from other drivers of the typical electricity bill.

In Table 15 below, we provide details on the consumer archetypes we use in this paper:

Table 15: Archetypical Customers

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

Note: For DG10 customers, ESBN 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 controls.
- 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,^{13, 14} 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).
- **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.

¹³ [CRU2023104 - Electricity Transmission Network Allowed Revenues for 2024 And Demand Transmission Use of System \(D-TUoS\) Tariffs 2023/24](#)

¹⁴ [CRU202482 - Electricity Transmission Network Allowed Revenues for 2025 And Demand Transmission Use of System \(D-TUoS\) Tariffs 2024/25](#)

A.3 Scenario Details

Table 16 below details the key parameters that are used in the four scenarios presented in this paper are detailed in below. Where data spans more than one scenario it is the same in all the scenarios it spans.

Table 16: Scenario Further Details (2024 Values)

Network Company	Company Baseline Ask	Company Full Ask	DD Baseline	DD High
DSO	Baseline only	AIMF included	Baseline only	AIMF included
	WACC (real, pre-tax): 4.23%		WACC (real, pre-tax): 3.85%	
	Opex: €3,011m		Opex: €2,517m (incl. frontier shift of €8m)	Opex: €2,769m (incl. frontier shift of €8m)
	Net Capex: €6,618m	Net Capex: €7,493m	Net Capex: €5,195m	Net Capex: €7,003m
OAO	Separate nominal WACCs for Phase 1 and Phase 2, with additional liquidity building block and Cost of Debt true-up.		WACC (real, pre-tax): 4.58%	
	Opex: €409m	Opex: €453m	Opex: €403m (incl. frontier shift of €15m)	Opex: €445m (incl. frontier shift of €15m)
	Net Capex: €778m	Net Capex: €4,503m	Net Capex: €777m	Net Capex: €4,502m
	Tonn Nua (Phase 2 project) estimated to cost €1.59bn, of which €348m incurred in PR6.			
	One Phase 1 asset transferred to EirGrid during PR6: Oriel Wind Park (delivery date Q2 2029, ATV: €335m plus stamp duty: €25m).	Six Phase 1 assets transferred to EirGrid during PR6 in line with EirGrid Business Plan.	One Phase 1 asset transferred to EirGrid during PR6: Oriel Wind Park (delivery date Q2 2029, ATV: €335m plus stamp duty: €25m).	Six Phase 1 assets transferred to EirGrid during PR6 in line with EirGrid Business Plan.
TAO	Baseline only	AIMF included	Baseline only	AIMF included

	WACC (real, pre-tax): 4.23%		WACC (real, pre-tax): 3.85%	
	Opex: €427m		Opex: €408.3m (incl. frontier shift of €1m)	
	Net Capex: €3,171m	Net Capex: €5,705m	Net Capex: €4,017m	Net Capex: €5,676m
TSO	WACC (real, pre-tax): 4.89% + Operational gearing margin		WACC (real, pre-tax): 5.23% ¹⁵	
	Controllable Opex: €950m		Controllable Opex: €771m (incl. frontier shift of €27m)	Controllable Opex: €851m (incl. frontier shift of €27m)
	Non-Controllable Opex ¹⁶ : €1,616m			
	Net Capex: €852m		Net Capex: €660m	Net Capex: €838m
	FASS: €1,568m			
	Exceptional Items: €745m			

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

¹⁵ 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%.

¹⁶ Excluding FASS and TAO payment.

A.4 FASS Estimated Values

For completeness, the values included for estimated FASS charges are provided in Table 17 below. The values are the same across all four scenarios. These are indicative impacts only.

Table 17: FASS Customer Impact Values by Archetype (€, Nominal Values)

Example Customer	2026-27	2027-28	2028-29	2029-30
Domestic	27	37	39	40
Small non-domestic	258	354	369	378
Medium non-domestic (1)	9,220	12,626	13,165	13,483
Medium non-domestic (2)	92,202	126,261	131,646	134,832
Large non-domestic	184,404	252,522	263,292	269,664
XLEU	1,401,471	1,919,167	2,001,017	2,049,447