

# Breakdown of Irish cost stack

## *Wind Energy Ireland & IrDEA*

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Rowan Hazell, Craig Lowrey, Hassan Khokhar, Ratnottama Sengupta, Anna Moss

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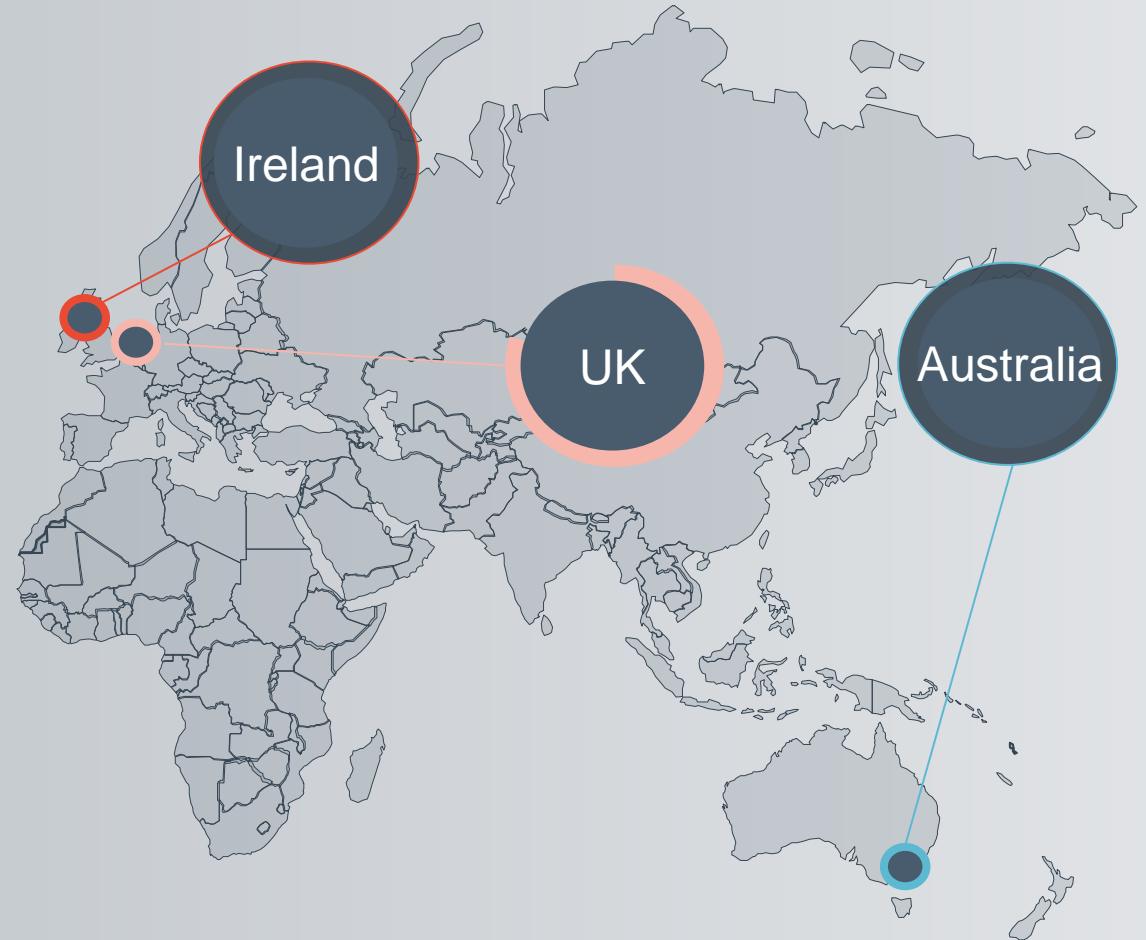
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# About this report

- The Irish Distributed Energy Association (“IrDEA”) and Wind Energy Ireland (“WEI”) are seeking to understand how the structure and balance of non-commodity costs in the electricity and gas bill may have implications for the decarbonisation of heat in Ireland
- This research includes:
  - Understanding the methodology used to apply non-commodity charges to end users
  - Understanding the relative balance of non-commodity costs between gas and electricity for end users over the last five years
  - An overview of any known subsidies
  - A qualitative view of upcoming policy and regulatory changes that may impact non-commodity costs

# 1. Executive summary



# Executive summary (1)

- There are several non-commodity charges in the Irish energy market that are recovered from consumers through electricity and gas bills. These charges typically support central industry functions, from network operation to market balancing costs, and include:
  - Transmission Use of System (TUoS) and Distribution Use of System (DUoS) charges for the use of the network
  - Public Service Obligation (PSO) Levy
  - Capacity charges
  - Imperfections charge
  - Market operator charges
  - Carbon tax
  - *NB: The complete electricity and gas bill includes commodity costs and supplier costs (e.g. staffing). These are not included in the analysis in this report*
- The aggregate non-commodity cost stack for electricity is larger its gas equivalent for the domestic, small business and large business consumer archetypes. On average over the 2018-2024 delivery years (October to September) analysed, the balance of non-commodity costs are:
  - 4.2 times higher in electricity than gas for a domestic consumer
  - 5.1 times higher in electricity than gas for a small business consumer
  - 3.9 times higher in electricity than gas for a large business consumer
- The electricity non-commodity cost stack recovers several additional charges which are not present in gas (including market operator charges, PSO levy, capacity market charge, imperfections charge)
  - In the 2023-24 charging year, these additional charges accounted for around 25% of the electricity stack for a domestic consumer,
  - The Carbon tax is the only charge included in gas, and not in electricity, accounting for 27% of the gas stack in the 2023-24 charging year for a domestic consumer
- ***This balance of costs therefore serves as a disincentive to switch from gas to the electrification of heat***

# Executive summary (2)

- Network costs account for around 75% of the non-commodity cost stack for both fuels for a domestic consumer in the 2023-24 charging year. Network related charges are higher on a €/MWh basis in electricity compared to gas, in the recovery of both transmission and distribution costs
  - Charges for electricity transmission (€28.35/MWh) are more than five times higher than the gas equivalent (€5.34/MWh), while the distribution costs (€54.38/MWh) are around three times higher compared to the gas equivalent (€17.84/MWh)
- Electricity network charges are set through a regulated price control focused on the cost recovery for the ownership and operation of the transmission and distribution networks over a defined five-year period
  - The largest transmission allowances made in 2024 under the most recent price control period (PR5) include those for ancillary services (18% of the total allowed revenue for 2024 recovered through TUoS) and new connections (8%).
  - In addition to these, adjustments were made for the Security of Supply programme, which in 2024 accounted for 36% of allowed revenue through TUoS. This programme was launched in 2021 with the intent of increasing generation capacity over the following four to five years by (not exclusively) delivering additional flexible gas-fired generation capacity by 2030, procuring temporary emergency generation for Winter 2022-23 and extending the operation of older generators
  - In the electricity distribution network, the largest allowances made in 2024 under PR5 were for smart metering (21%), followed by networks rates tax and planned maintenance (6% each)
- The majority of electricity network costs are recovered from demand users. For 2023-24, ~93% of Ireland TUoS costs are recovered from demand, with the remainder recovered through generation network costs. Electricity distribution charges are 100% recovered from demand users
- Gas network charges are also set through a price control determined on a similar basis to those for electricity
  - The largest allowances in the most recent price control period (PR5) are for pass-through costs (including shrinkage, CO<sub>2</sub> costs, commercial property rates, CRU levy) at €279mn, accounting for 24% of the allowances in the five-year period
  - The largest gas distribution allowances arise from asset operational costs (17%)
  - 100% of gas network costs are recovered from demand customers via shippers and suppliers
- 100% of gas network costs are recovered from demand customers via shippers and suppliers
- The recovery of electricity and gas network costs is explored further in Section 2

# Executive summary (3)

- A proposed change to the arrangements for offshore grid charging policies from the CRU may see additional costs passed through network charges to electricity consumers. Currently in consultation, the proposals are seeking views on how to recover the costs of offshore transmission assets constructed by EirGrid for Phase 2 assets. Two options are proposed. Under the option 2, the costs of offshore transmission assets would be socialised across all electricity consumers through D-TUoS tariff. This would result in an increase of €7-10/yr for an average household, representing a ~10-15% increase for the network charging element
  - The CRU noted it does not have a preferred option at this time
- The PSO Levy is the most variable cost in the non-commodity stack. The Levy recovers costs of supporting the build out of renewable capacity in Ireland (currently the RESS and REFIT schemes) and the charge is set by the CRU annually based on expected wholesale prices. The RESS scheme is based on a two-way contract for difference, so changes in the wholesale price influences the price paid or received by consumers. In 2022-23 most customers saw a credit in their bills due to the high wholesale prices where the CRU determined that there was a funding requirement of -€491.2mn. In 2023-24 with wholesale prices dropping the funding requirement was adjusted to -€67.47 million, which saw the PSO payment in bills being set at zero
  - One of the input costs to the PSO Levy comes through the REFIT scheme, which provides renewable assets with a one-way contract for difference (CfD) for 15 years. The scheme ended in 2015 to new generation, and the costs of the existing contracts are expected to reduce over time as they roll off, with backstop end dates arising from 2027 to 2030
  - However, the Irish government has ambitious targets for decarbonisation, including the continued deployment of renewable generation. As additional renewable capacity is deployed to meet decarbonisation targets the expected cost of PSO will increase (subject to movements of the wholesale price). In the near term as wholesale electricity prices are expected to decrease to the mid-2030s this indicates the cost of the PSO will increase
- In 2024, a new charge is expected to be included in the cost stack for the Renewable Heat Obligation. This new measure places an obligation on suppliers of heat to include a proportion of supply from renewable sources. The initial rate is expected to be set at 0.5% and rise to at least 3% over the decade, and is currently proposed to impact all providers of oil, LPG, natural gas, coal and peat. We expect costs to be passed back through to consumers through their heat supplier. Year 1 (2024) of the scheme is expected to cost equivalent to around €4-€9/year for a household depending on consumption, rising to €24-€54/year by 2030. For I&C consumers, this ranges from <0.7%-<1.5% of the bill in year 1 to <3%-6% of the bill in 2030
  - The Renewable Heat Obligation proposals do not currently include electricity supplied for heat, although this has been raised as a question in the latest design consultation. We therefore expect to see increases to gas and other heating fuel bills, but not in electricity bills
- Many of the proposed changes to non-commodity costs currently in scope are not expected to have a material impact on consumer bills in the short term, although we continue to expect additional variability in costs year to year, and potential intervention to reduce volatility (as with the PSO Levy in 2023-24)

# Summary of charges

	Charge	Summary	% of non-commodity stack
NETWORKS	Transmission Network use of System (TNUoS)	Transmission use of system charges are used to recover the costs incurred by the transportation of bulk power across the system interconnecting to the low power distribution system	24-34%
	Distribution Use of System (DUoS)	Distribution use of system charges are the cost of operating and investing in the electricity network during the lifetime of the connection	43-52%
POLICY	PSO Levy	It recovers funds that support renewable generation, currently the renewable electricity Feed-In tariff (REFIT) and the renewable electricity scheme (RESS)	0-15%
	Capacity Market (CM)	Scheme to ensure system has enough capacity to meet maximum demand	14-19%
MARKET	Market Operator charge	Market operator charges recover the operational costs of SEMO's balancing market functions, along with capital related costs including a rate of return	~1%
	Imperfections charge	The imperfection charge is used to recover costs that cannot be recovered through the other charges in imbalance settlement.	10-13%

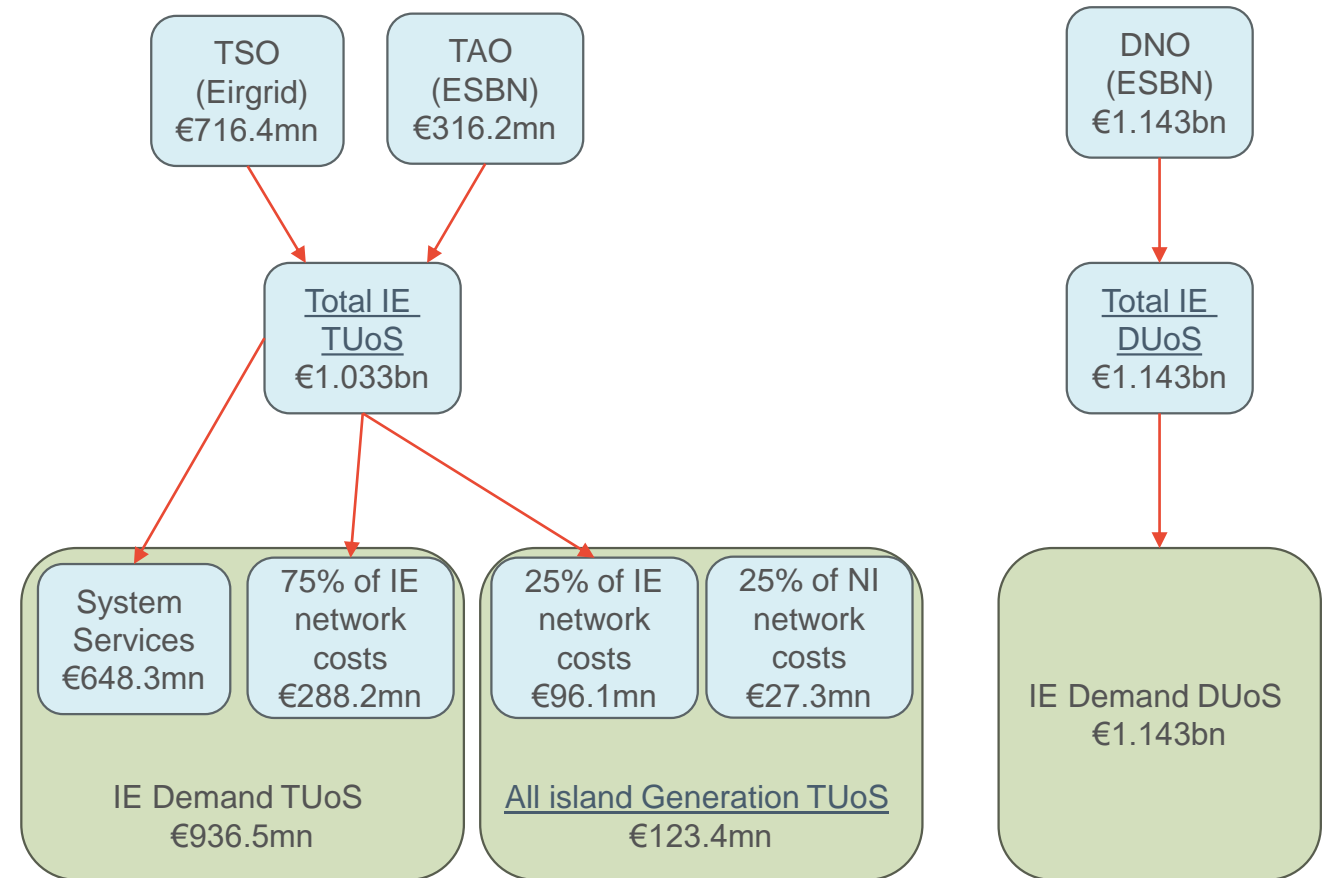
## 2. Network cost recovery



# Electricity network cost recovery

Figure 1: Indicative view of 2023-24 electricity network cost recovery

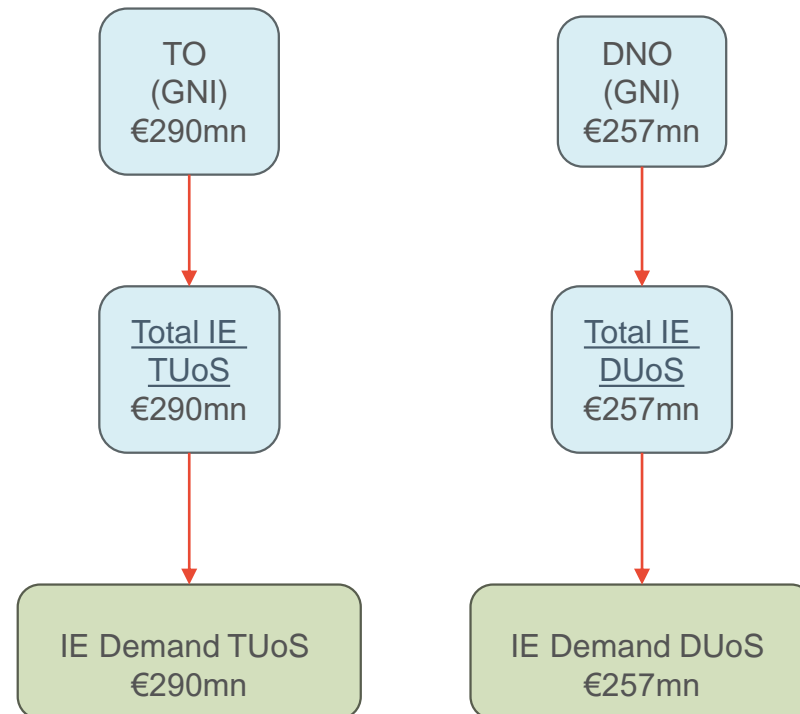
- Electricity transmission charges recover allowed revenues for Eirgrid as the Transmission System Operator (TSO) and ESB Networks (ESBN) as the Transmission Asset Owner (TAO)
  - 100% of TSO external costs and 40% of TSO internal costs are treated as System Services costs. These are all recovered from Demand TUoS
  - 100% of TAO costs and 60% of TSO internal costs are treated as network costs. 75% of network costs are recovered from Demand TUoS, with 25% of costs being recovered from generation through an all island pot, which includes 25% of Northern Ireland's transmission network costs
  - As shown in Figure 1, the recovery approach means that for 2023-24, ~93% of Ireland TUoS costs are recovered from demand
- Electricity distribution charges recover ESBN's costs of owning and operating the distribution network
  - 100% of distribution network costs are recovered from demand customers



# Gas network cost recovery

- Gas transmission charges recover allowed revenues for Gas Networks Ireland as the Transmission System Owner and Operator
- Gas distribution charges recover ESB Networks' costs of owning and operating the distribution network
- 100% of gas network costs are recovered from demand customers via shippers and suppliers

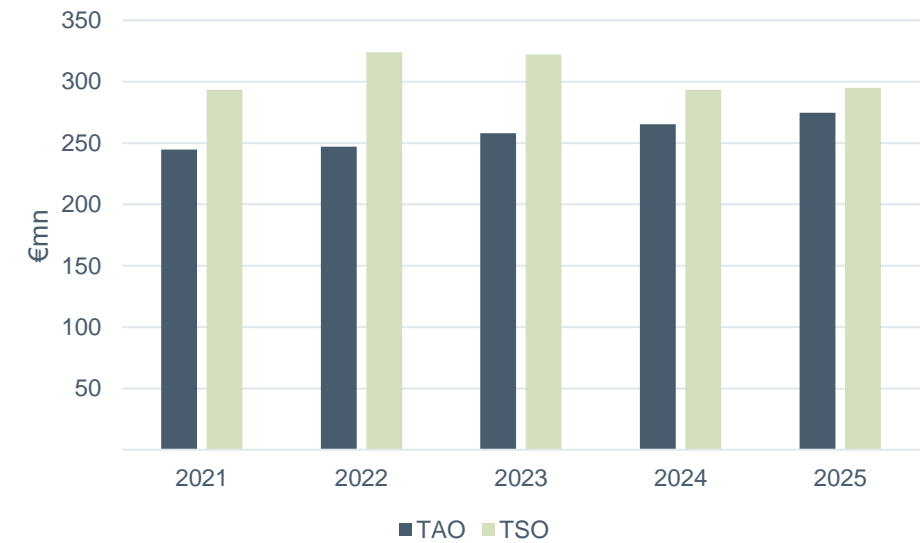
Figure 2: Indicative view of 2023-24 gas network cost recovery



# Electricity transmission network cost elements

- Allowed revenues for the electricity transmission companies are set on a calendar year basis through the price control process, the current iteration being Price Review 5 (PR5) which is running from 2021-2025.
- A decision on PR5 was made in December 2020, providing an initial €2.8bn of revenues for Eirgrid and ESBN's transmission operations over the five year period
- PR5 allowances can be broadly broken down into operating expenditure (opex), capital expenditure (capex), and adjustments from the previous price control (PR4)
- For ESBN the largest PR5 cost allowances are (in 2019 prices):
  - New connections (capex): €376.3mn
  - Ongoing projects (capex): €455.5mn
  - Asset refurbishment (capex): €198.9mn
  - Local authority rates (opex): €162.4mn
- For Eirgrid, the largest PR5 allowances are (in 2019 prices):
  - Ancillary services (opex): €918.6mn
  - Staff costs (opex): €176.5mn
- For transmission operational expenditure increased by ~52% from PR4, with capital expenditure up by ~35%

Figure 3: 2021-25 electricity transmission PR5 revenues

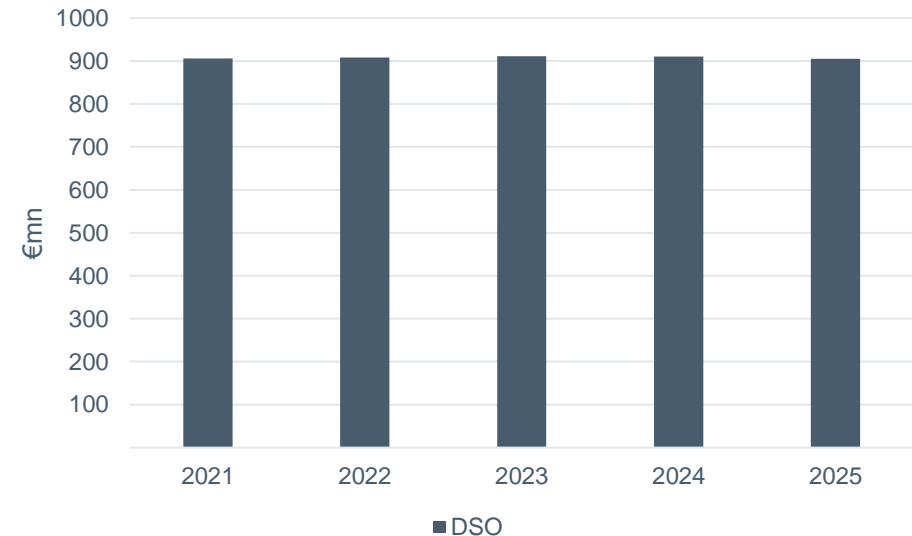


Source: Cornwall Insight, [CRU](#)

# Electricity distribution network cost elements

- Allowed revenues for ESB Networks as the Distribution Network Operator are also set on a calendar year basis through the PR5 price control process
- A decision on PR5 was made in December 2020, providing an initial €4.5bn of revenues for ESBN's distribution operations over the five year period
- The largest areas of expenditure over the five years include (2019 prices):
  - Smart metering (capex): €882.1mn
  - Network rates (opex): €329.6mn
  - Planned maintenance (opex): €328.3mn
  - Unplanned maintenance (opex): €207.26mn
  - Generation connections (capex): €193.4mn
  - New housing schemes (capex): €172.4mn
  - System control (opex): €91.3mn
- For distribution, operational expenditure was up by ~20% and capital expenditure up by ~84%

Figure 4: 2021-25 electricity distribution PR5 revenues

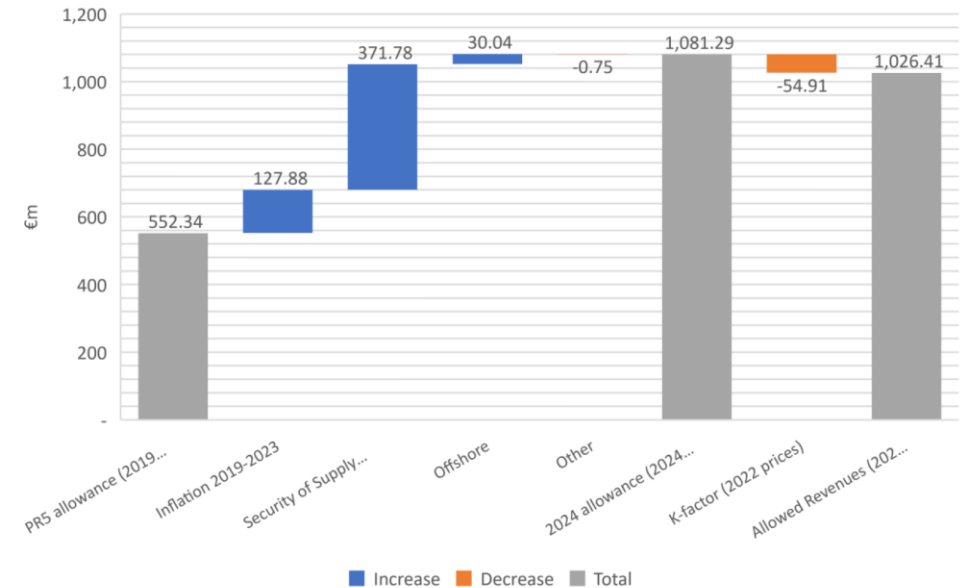


Source: Cornwall Insight, [CRU](#)

# Electricity transmission 2024 revenue adjustments

- Initial PR5 allowances set in 2020 are adjusted ahead of each calendar year to determine total allowed revenues
- For ESBN the largest PR5 cost allowances for 2024 are (in 2019 prices):
  - New connections (capex): €78.9mn
  - Ongoing projects (capex): €51.3mn
  - Asset refurbishment (capex): €41.8mn
  - Local authority rates (opex): €32.8mn
- For Eirgrid, the largest PR5 allowances for 2024 are (in 2019 prices):
  - Ancillary services (opex): €182.9mn
  - Staff costs (opex): €35.3mn
  - East West Interconnector Support Fees (opex): €21.4mn
- In total the PR5 allowances for 2024 are €552.34mn. Adjustments have been made to account for a range of additional costs including the Security of Supply programme (+€371.78mn) and inflation (+€127.88mn). When accounting for under recovery from the previous year, the total allowed revenue for 2024 to be recovered through TUoS is €1.026bn
  - The Security of Electricity Supply programme saw the introduction of the Development (Emergency Electricity Generation) Act 2022, which included provisions for the installation of up to 450MW of temporary emergency generation by winter 2023-24. Eirgrid forecast costs of €371.78mn for the 2024 revenue requirement, covering the procurement of the generation and associated activities

Figure 5: 2024 transmission network allowed revenues

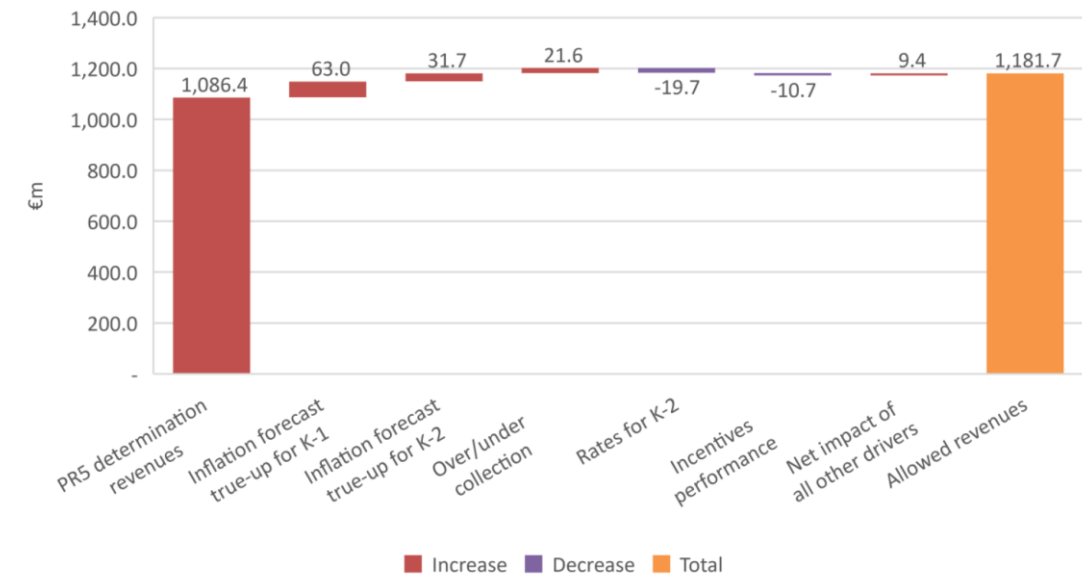


Source: CRU

# Electricity distribution 2024 revenue adjustments

- The largest initial PR5 cost areas for 2024 are (2019 prices):
  - Smart metering (capex): €229.7mn
  - Network rates tax (opex): €66.6mn
  - Planned maintenance (opex): €65.3mn
  - Fault maintenance (opex): €41.8mn
  - System control (capex): €37.6mn
  - Generation connection reinforcements (capex): €36.5mn
  - MVLV system improvements (capex): €35.2mn
  - New housing schemes (capex): €34.7mn
  - MV overhead line renewal (capex): €34.1mn
  - 110kV new business (capex): €31.5mn
- For 2024, the total initial PR5 allowed revenues are €1.086bn. Additional adjustments include inflation (€94.7mn) and under collection (€21.6mn), but the revenues in addition to those provided under the PR5 determination are notably lower than for the transmission networks. The total to be recovered for 2024 is €1.182bn

Figure 6: 2024 distribution network allowed revenues



Source: [CRU](#)

# New electricity connections

A customer is charged for a connection charge for setting up a new connection, which comprises of five different elements as mentioned in the [ESBN Basis of Charges for Connection](#)

- Standard MIC charge
  - Customers are liable to standard charges to recover a part of the DSO's costs for providing new connections. These are the costs of dedicated connection asset that is required by DSO for installing metering, cables and other equipment required to effect the connection
  - The charges are calculated by establishing the range of least cost technically acceptable (LCTA) connection method which is the least cost while including the development cost which will be required by the DSO for necessary development infrastructure in the future
  - The customer is quoted 50% of this cost. In instances where costs overrun the LCTA estimate, the costs over and above that estimate are recovered in full through the customer.
  - Business customers are liable to capacity charge, which is the average charge per kVA for reinforcement of the existing system.
  - It is 50% of the cost of the customer's share of the capacity of the MV/LV substation and 25% of the average cost of network reinforcement (applicable to business customers with an MIC of 500kVA or greater)
- Network charge
  - MV network costs are included in the standard MIC charge for standard 12 kVA and enhanced 16 kVA connections within defined distance criteria (which is usually on the average length of roadway), outside these criteria additional MV network charges apply.
  - The standard MIC charge does not include network charges but instead standard charges per metre are used for 20kVA and 29kVA special connections to domestic customers, domestic customers with apartment connections and business customers

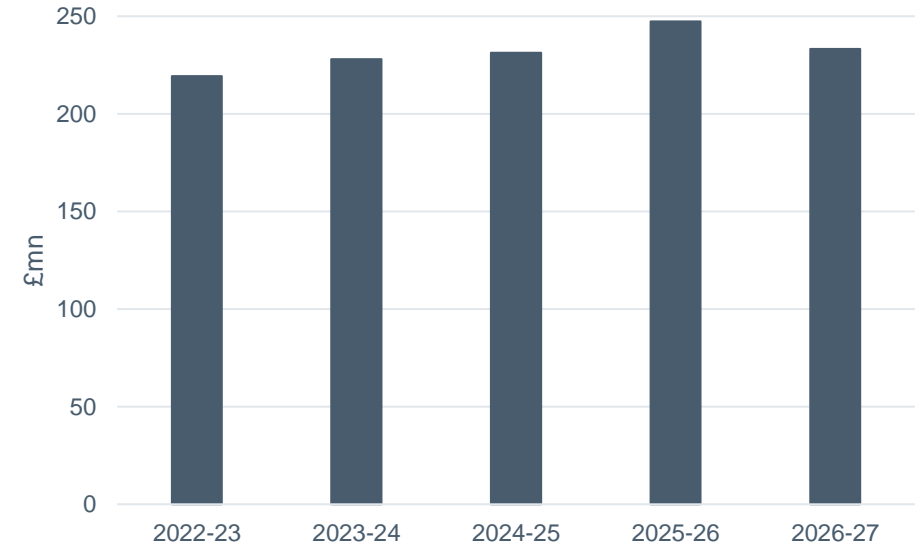
# New electricity connections

- Trenching charge
  - The trenching required to effect the connection is always the responsibility of the customer both inside and outside the site.
  - The trenching cost are fully incurred by customer both inside and outside the site.
  - In case the customer requests for trenching through ESB , the ESB can provide quotation for trenching cost through external contractors but are to be paid by the customers in full
- Exceptional charge
  - These are additional costs that includes any third party activities or additional scope of work which are explained below
  - High Trenching costs: The customer is charged with full contractor trenching charge where the actual trenching charge is over 110% of the standard trenching charge
  - Additional charges: The allied charges including local authority road opening charges and any wayleave, easement or other costs imposed by third parties are charged in full.
  - Supplementary charges (Businesses only): Theses are only applicable to business customers because of the extra cost of providing capacity on these networks, where the length of feeding network is exceptional.
  - All of the charges are to be paid by customers in full
- Shared Network charge
  - A shared network charge / refund is only applicable where a connection to a new customer makes use of the connection asset of an existing customer once certain eligibility criteria and conditions are met as outlined in the charges of connection by ESB

# Gas transmission network cost elements

- For gas, the price control process also runs on a five year basis, with the current iteration being Price Control 5 (PC5) which runs from October 2022 – September 2027
- A decision on PC5 was made in December 2023, providing an initial €1.16bn of revenues for Gas Networks Ireland's transmission operations over the five year period
- The largest areas of expenditure over the five years include (2020-21 prices):
  - Pass-through costs (including shrinkage, CO2 costs, commercial property rates, CRU levy): €279mn
  - Transmission connections (capex): €187.7mn
  - Asset operations (opex): €150.1mn
  - Compressors (capex): €88.8mn
- Opex allowances have increased by 52% relative to PC4, primarily due to the need for investment focusing on security of supply and network operation, while connecting more flexible generation to support decarbonisation. Capex allowances are up by 8%
- 2022-23 and 2023-24 tariffs were set using PC4 revenues as the war in Ukraine and the wider policy context delayed the PC5 decision. A reconciliation process is planned following the December decision
- Allowed revenues will be updated on an annual basis to reflect changes to pass-through costs and extra-over items, over/under recoveries in the previous years and updated demand projections

Figure 7: 2022-27 gas transmission PC5 revenues

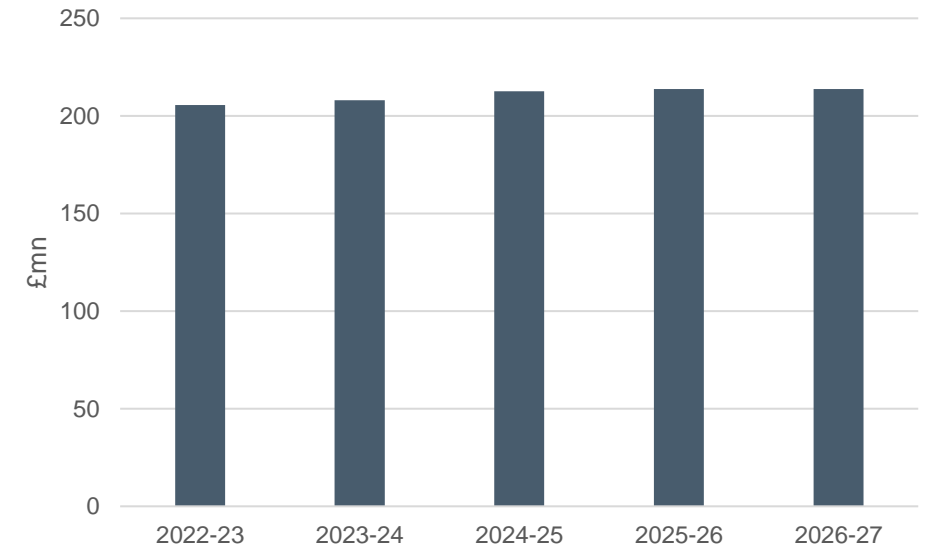


Source: Cornwall Insight, [CRU](#)

# Gas distribution network cost elements

- For gas, the price control process also runs on a five year basis, with the current iteration being Price Control 5 (PC5) which runs from October 2022 – September 2027
- A decision on PC5 was made in December 2023, providing an initial €1.05bn of revenues for Gas Networks Ireland's distribution operations over the five year period
- The largest areas of expenditure over the five years include (2020-21 prices):
  - Asset operations (opex): €191.7mn
  - Meter replacement programmes (capex): €122.1mn
  - Pass through costs (including shrinkage, CO2 costs, commercial property rates, CRU levy): €122.8mn
  - IT (opex): €43.5mn
- Opex allowances will increase by 11% compared to PC4, with capex allowances increasing by 9%
- 2022-23 and 2023-24 tariffs were set using PC4 revenues as the war in Ukraine and the wider policy context delayed the PC5 decision. A reconciliation process is planned following the December decision
- Allowed revenues will be updated on an annual basis to reflect changes to pass-through costs and extra-over items, over/under recoveries in the previous years and updated demand projections

Figure 8: 2022-27 gas distribution PC5 revenues



Source: Cornwall Insight, [CRU](#)

# New gas connections costs (1)

Gas Networks Ireland sets out new connections cost methodologies for household and business users in its [Connections Policy Document](#). The recovery of connection costs is split between upfront charges, supplemental charges (based on an economic test) and tariffs.

## Large I&C customers

- Large I&C customers are required to make payments equal to the full capital costs of new connections. A refund mechanism then operates for five years, where new loads benefit subsequently from the reinforcements already made
- For example, a large I&C customer will pay the full connection cost (€3m) upfront for the direct cost of the connection plus the full cost of the upstream reinforcement (€20m)

## Medium/Small I&C customer

- Medium/Small I&C customers pay a standard contribution of 30% of the estimated full pipeline and ancillary equipment capital costs based on transmission and distribution costs (where applicable). In addition, Gas Networks Ireland assesses whether a supplemental “economic test” contribution is required
  - The supplemental contribution is based on an economic test, which is to provide for the shortfall in the remaining capital costs of the connection that will not be recovered through attributable tariff payments by the customer over a seven year period
- The actual connection costs, over and above the standard contribution and any supplemental economic test contribution, will be recovered through general tariff payments
- For example, Medium/Small I&C customers will pay 30% (circa €1m) upfront for the direct cost of the connection plus 30% (circa €6m) of the present value of the upstream reinforcement plus any supplemental contribution if required. The other 70% (circa €16m) of the costs, both shallow and deep, would be recouped from capacity payments. Any costs over and above those outlined would be recovered through general tariff payments.

# New gas connection costs (2)

## Domestic customer

- For individual households, all loads with an expected annual consumption of up to 73,250 kWh will be liable for the standard domestic connection charge of €249.70 (incl. VAT) for the first 15 metres of service pipe. Customers requiring a service connection (with no gas mains extension) of greater than 15 metres will be required to pay an incremental fixed charge per metre of €51.32 (incl. VAT) in addition to the standard connection charge.
- For new housing developments there are two components: the standard domestic connection charge and a supplemental “economic test” contribution
  - The supplemental contribution will consider the full connection costs against 80% of the distribution tariff revenue attributable to the facility and 100% of the transmission exit tariff revenue and 75% of the entry tariff revenue, all over a 20 year time horizon

## Summary

- New connection costs for large I&C users that have a significant impact on the network are charged at a full connection cost to incentivise location near the network
- New connection costs for commercial customers are evaluated over a shorter time horizon as they do not tend to have the same longevity as domestic customers. Part of the costs are recovered through capacity charges across all network users
- New connection costs for domestic customers are charged consistently for each new user. Domestic connections are evaluated over a longer time horizon

# Losses

- Charges are either applied at the trading point (i.e. volumes before network transportation) or the selling point (volumes at the customer's site)
- Transmission charges are based on consumption at the trading point, and so Distribution Loss Adjustment Factors need to be applied to metered consumption volumes

# 3. Methodology of cost recovery – electricity bill



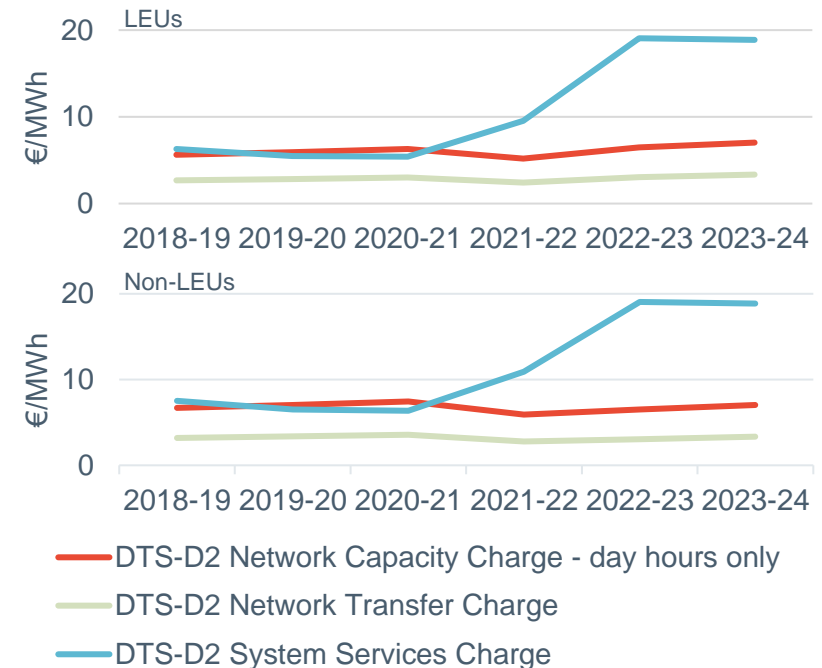
# Network usage charge - Transmission

## Network usage charge - transmission

### Summary of recovery

- Transmission Use of System (TUoS) charges are levied by the Transmission System Operator (TSO), EirGrid on demand (suppliers) and generators/auto-producers, with charges recovered monthly
- Charges are confirmed in September ahead of the 1 October – 30 September charging year
- There are three main categories of charge for demand customers
  - DTS-T: for transmission connected customers
  - DTS-D1: for distribution connected customers with a Maximum Import Capacity (MIC) of  $\geq 0.5\text{MW}$
  - DTS-D2: other distribution connected customers
- DTS-D1 and DTS-D2 charges were previously differentiated between Large Energy Users (those connected at  $>10\text{kV}$ ) and non-Large Energy Users, but since October 2022 the same charges have applied regardless of LEU status
- Charges include a network capacity charge (€/MW for DTS-T and DTS-1, €/MWh 8:00-23:00 for DTS-2), network transfer charge (€/MWh) and a system service charge (€/MWh). The transmission connected system services charge is split between peak (17:00-19:00) and off peak demand
- Between 2018 and 2023 there have been increases in both network capacity and network transfer charges of 5% for non-LEUs and between 13%-25% for LEUs. The change is not linear and has included a likely COVID related adjustment (downward trajectory) in 2021-22

Figure 9: Transmission charges for DTS-D2 demand users, October-October charging years



Source: Cornwall Insight, EirGrid

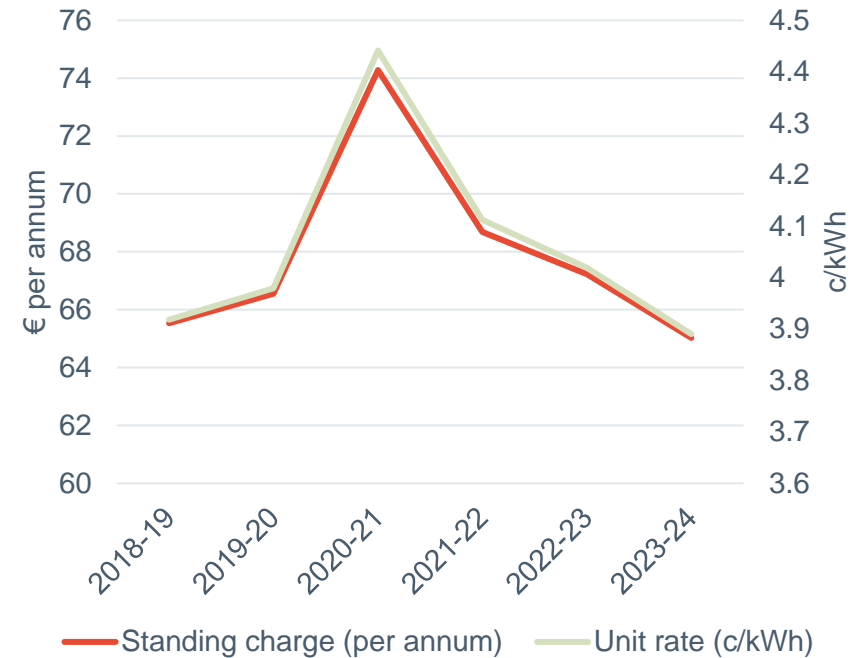
# Network usage charge - Distribution

## Network usage charge - Distribution

### Summary of recovery

- Distribution Use of System (DUoS) charges are approved by the CRU and charged by ESB Networks
- They are levied on users of the electricity distribution system, who are grouped into one of 14 DUoS groups
- For domestic users costs are recovered through an annual (prorated) €/meter standing charge and cent per kWh unit charges which are flat for standard meters, and Time of Use (peak/day off peak/night off peak) or day/night tariffs where capable meters are installed
  - Between 2018-19 and 2023-24 the charges have remained relatively steady, with abnormally high charges for 2020-21 primarily due to an under-recovery in 2020 resulting from Covid-19 driven demand reduction
- For non-domestic users, costs are recovered through an annual €/meter standing charge, a capacity charge, a unit rate (similar structure to domestic customers) and a low power factor surcharge
  - Across groupings between 2018-19 and 2023-24 charges have increased by ~200% or more

Figure 10: DUoS charges for standard meter domestic (urban) customer, October-October charging years



Source: Cornwall Insight, ESB

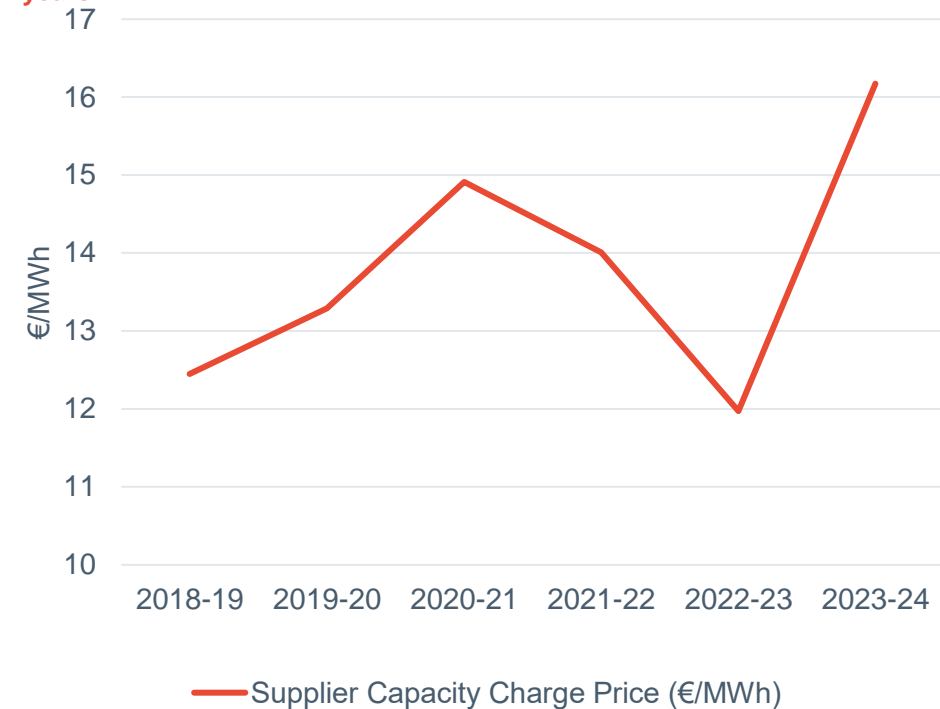
# Capacity charge

## Capacity charge

### Summary of recovery

- Capacity charges recover the anticipated costs of the Capacity Payments to Capacity Market Units
- Charges are published by SEMO for each charging year of 1 October – 30 September
- Suppliers are charged for each settlement period between 7am and 11pm. Charges for each period are calculated by multiplying the Supplier Capacity Charge Price by metered volumes and the applicable Capacity Charge Metered Quantity Factor, which can be set to 0 or 1. If set to 0 (for night-time hours), no charge will apply in the settlement period
- Additionally, suppliers will face Difference Payment Socialisation Charges, which are calculated by multiplying the Supplier Capacity Charge Price by metered volumes, the applicable Capacity Charge Metered Quantity Factor, and the Difference Payment Socialisation Multiplier for the year. This will usually make up a relatively small proportion of the overall capacity charges

Figure 11: Supplier Capacity Charge Prices. October – October charging years



Source: Cornwall Insight, SEMO

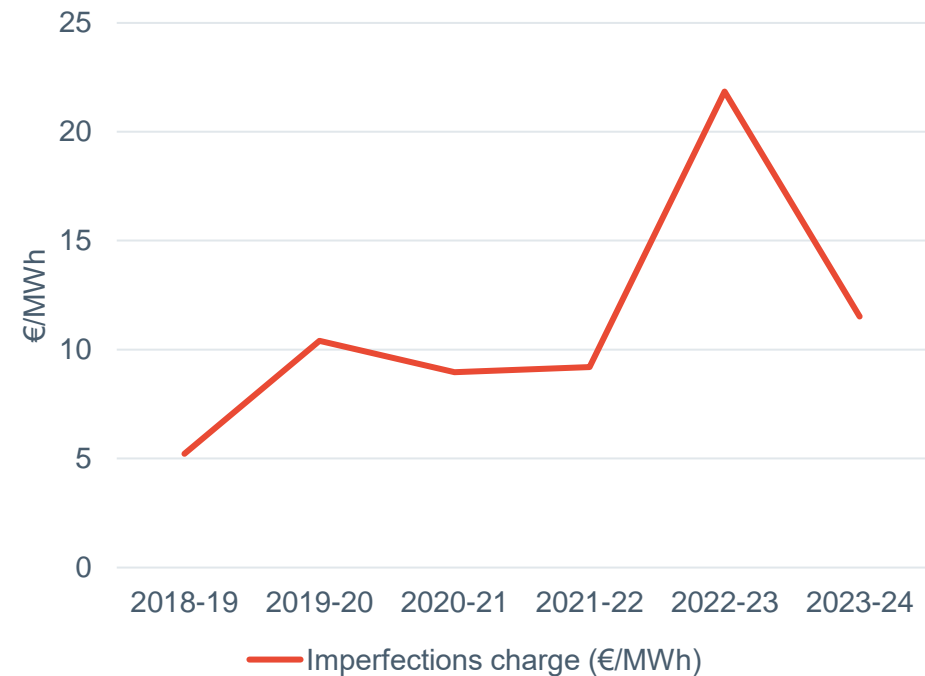
# Imperfections charge

## Imperfections charge

### Summary of recovery

- The Imperfections Charge is used to recover costs that cannot be recovered through the other charges in Imbalance Settlement. These costs include:
  - Dispatch Balancing Costs
  - Fixed Cost Payments and Charges
  - Net imbalances between Trading Payments and Trading Charges
  - Differences between Capacity Payments and Capacity Charges (although there are already other mechanisms in place to deal with this)
- SEMO publishes charges on an annual basis for 1 October – 30 September charging years
- The charge is levied on a supplier's net metered demand, with a fixed €/MWh tariff in all hours based on a forecast of the costs for the following year. Adjustments can be made for the current year if required
- Wholesale costs have a strong influence on the Imperfections Charge. The spike in 2022-23 was primarily due to high gas market prices

Figure 12: Imperfections charge rates, October-October charging year



Source: Cornwall Insight, SEMO

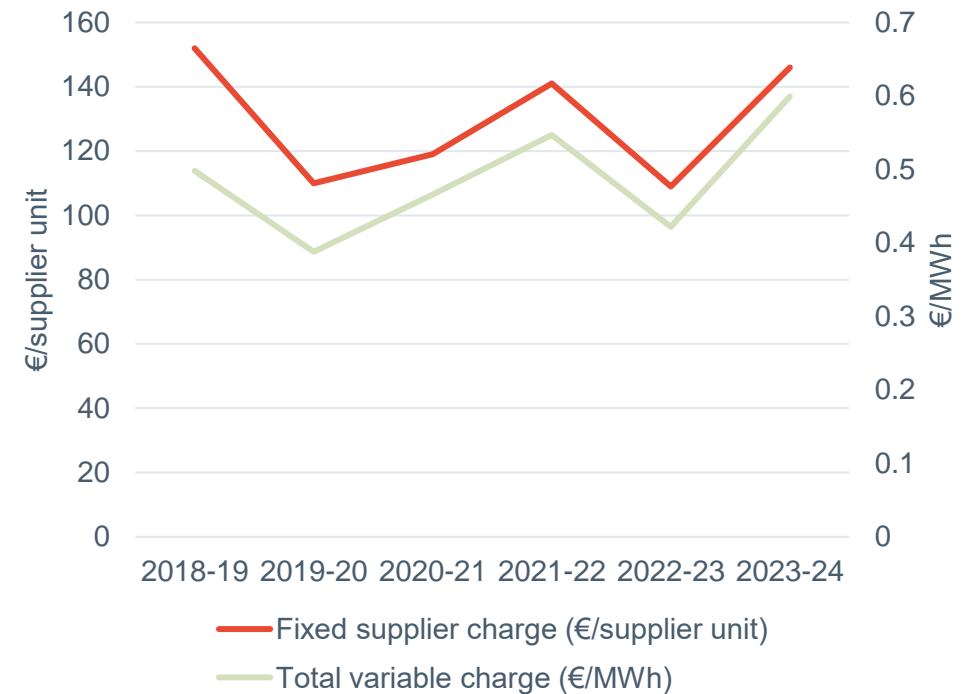
# Market Operator charges

## Market operator cost

### Summary of recovery

- Market Operator charges recover the operational costs of SEMO's balancing market functions, along with capital related costs including a rate of return
- Charges are set on an annual basis and recovered over a charging year of 1 October – 30 September
- Fixed supplier charges are recovered on a €/supplier unit basis
- Approaches to the fixed supplier charge cost recovery from customers will vary by supplier, but for the purposes of this analysis we have calculated a per customer cost based on the number of customers (~2,500,000) and supplier units (207) in the market
- The total variable charge element is recovered on a €/MWh basis

Figure 13: Market operator charge rates, October – October charging years



Source: Cornwall Insight, SEMO

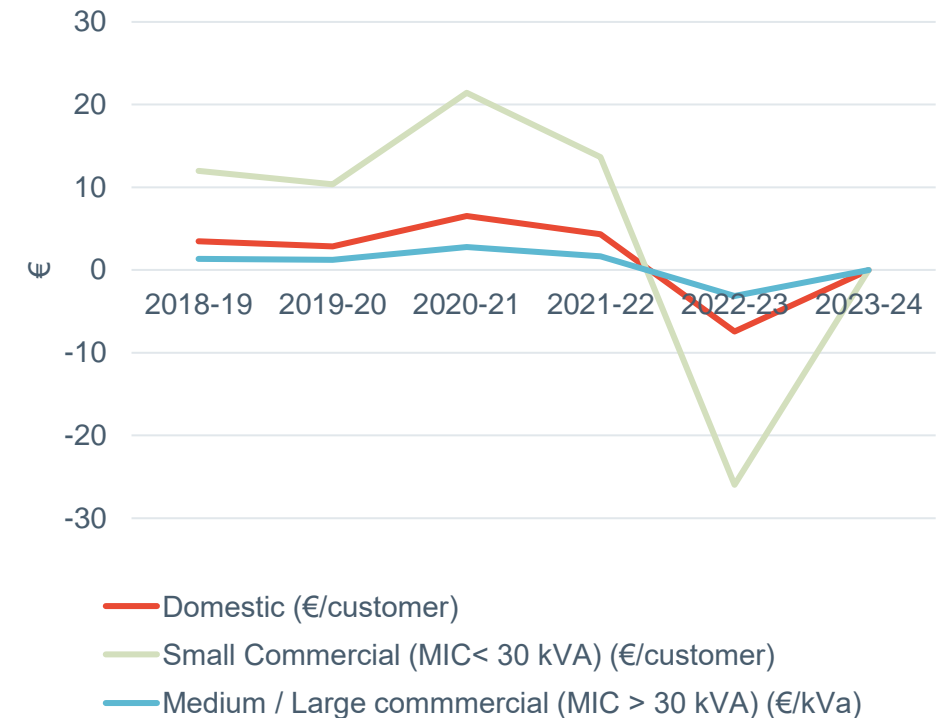
# PSO Levy

## PSO levy

### Summary of recovery

- The Public Service Obligation (PSO) levy is charged or credited to all electricity customers and recovers funds that support renewable generation, currently the Renewable Electricity Feed-In Tariff (REFIT, which has since closed to new applications) and the Renewable Electricity Support Scheme (RESS)
- The levy is calculated by the CRU on an annual basis, with the charging year running from 1 October to 30 September
- For domestic customers and small commercial businesses (the latter being defined as a site with a capacity of less than 30kVA), the levy is a monthly per customer charge
- For medium / large commercial businesses the levy is calculated on a per kVA basis and recovered monthly
- The levy became negative in 2022-23, due to the inverse relationship between the PSO and the wholesale electricity price. However, for the 2023-24 year, despite the funding requirement being negative, the CRU has set the PSO to zero to mitigate volatility and reduce the impact of forecast higher charges in 2024-25

Figure 14: Monthly PSO Levy rates, October – October charging years



Source: Cornwall Insight, CRU

# PSO Levy – additional details

## PSO levy – additional details

### What costs are recovered through the PSO levy

- The PSO levy recovers costs of supporting the build out of renewable capacity in Ireland, and is set by the CRU annually based on expected wholesale prices
- The two renewable auctions that have been instrumental in enabling renewables capacity recently are the REFIT and RESS/ORESS auctions, both of which are supported through the PSO levy
- REFIT which ended in 2015 and provided support for 15 years was a one-way contract for difference (CfD) where an asset was topped up to their strike price when the wholesale reference price was lower but did not have to pay back into the PSO pot if the wholesale price was higher than strike price. This helped cap the variability of the PSO levy
- In case of RESS / ORESS, a two-way CfD, the asset is paid when wholesale prices are lower than strike price and they would need to pay into the PSO pot if wholesale prices are higher than strike price. This adds to the volatility of the PSO levy, and customers could see a credit or a debit on their bills
- RESS3 / ORESS 1 strike prices are partially indexed to the HICP

### Drivers of PSO levy

- The PSO levy costs reflect the difference between generator contracted strike prices and wholesale prices on the SEM
- In 2022-23 most customers saw a credit in their bills due to the high wholesale prices where the CRU determined that there was a funding requirement of -€491.25 million
- In 2023-24 with wholesale prices dropping the funding requirement was adjusted to -€67.47 million, which saw the PSO payment in bills being set at zero
- This meant that customers did not receive the credit they saw in their bills in the previous PSO year (2022-23)
- Based on wholesale electricity price movements the PSO will remain a relatively volatile part of a customer's bills
- With high targets for renewable capacity until 2030 (80% of overall electricity generating capacity), the overall impact can be expected to increase over time

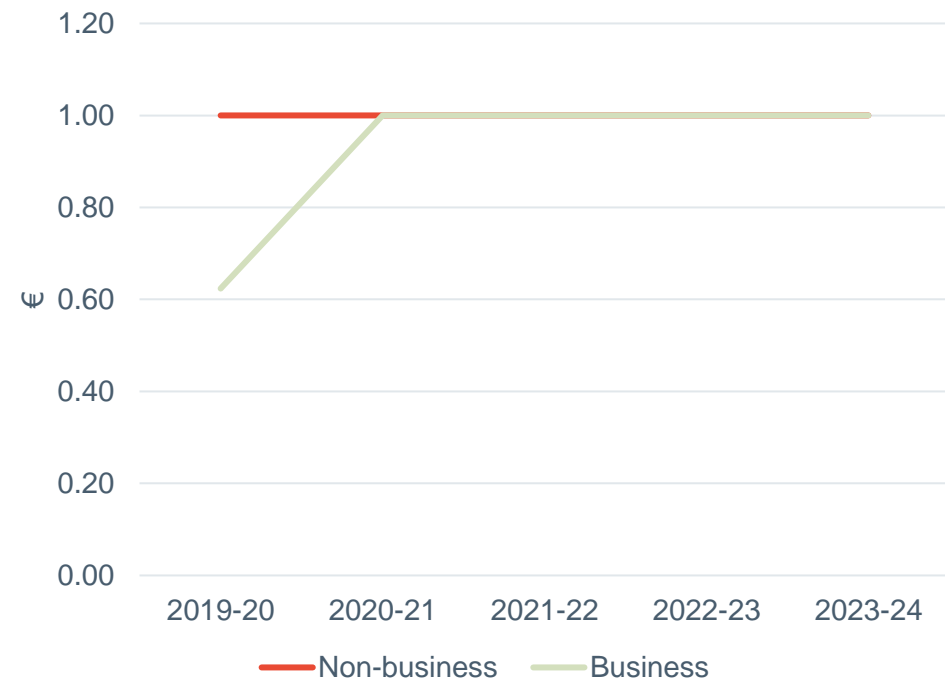
# Electricity tax

## Electricity tax

### Summary of recovery

- Electricity tax applies to non-domestic electricity volumes
- The tax was introduced in October 2008. This was in order to meet the requirements of the EU Energy Tax Directive, which requires all Member States to introduce an excise tax on electricity, with prescribed minimum rates. This is intended to avoid distortion of competition through different tax systems and support climate goals
- A rate of €1.00/MWh has applied to business and non-business (excluding domestic) use since 31 December 2019. Previously a non-business rate of €0.50/MWh was applied

Figure 15: Annualised electricity tax rates\*. Financial years.



\*Business rate of €0.50 applied until 31 December 2019

Source: Cornwall Insight, Revenue

# 4. Method of cost recovery - gas



# Gas transmission charges

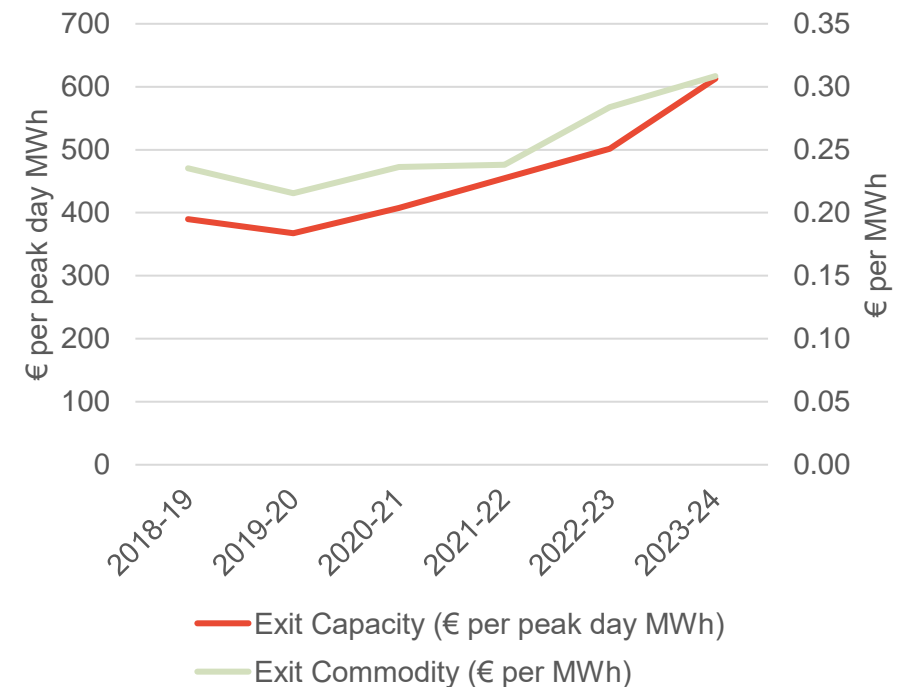
13-17% of  
gas non -  
commodity  
stack

## Gas transmission charges

### Summary of recovery

- Gas transmission charges consist of entry and exit charges, both of which have capacity and commodity-based elements.
- The commodity-based element is determined by how much gas is put on and taken off the transmission system on a €/MWh basis
- Capacity charges are levied on the amount of capacity booked for the gas year (or topped up through short-term products) which determines the maximum amount of gas the customer can use for any given day. Different capacity charges apply based on the entry and exit points that are used to flow gas on and off the transmission system
- There are currently five entry points, each of which has its own capacity charge, recovered on a € per peak day MWh basis. There are three exit points each with its own € per peak day MWh capacity charge
- The commodity charge is uniform across all entry points, and is recovered on a €/MWh basis. This method is the same across exit points
- As such, the customer's charge is influenced by the entry and exit points used, the capacity booked for each gas year, and the amount of gas used by the customer.

Figure 16: Domestic gas transmission onshore exit charges.  
October – October year



Source: Cornwall Insight, [CRU](#)

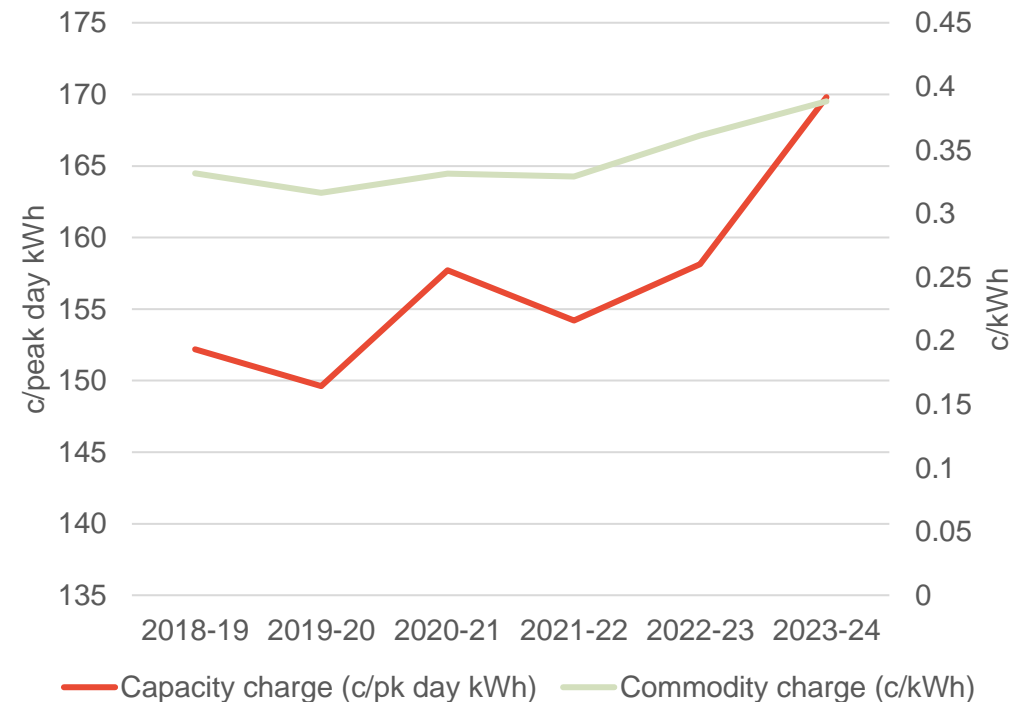
# Gas distribution charges

## Gas distribution charges

### Summary of recovery

- Like gas transmission charges, gas distribution charges consist of capacity and commodity based elements. Customers are allocated to one of four bands which are based on Annual Quantity (an estimate of consumption based on historical levels). These are:
  - $\leq 73$  MWh
  - $> 73$  MWh -  $\leq 14,653$  MWh
  - $> 14,653$  MWh -  $\leq 57,500$  MWh
  - $> 57,500$  MWh
- Capacity charges are levied on a c/peak day kWh basis, with commodity charges levied on a c/kWh basis. For 73-57,500MWh sites, the calculation of the charge itself includes an input of the sites' Maximum Daily Quantity (MDQ). For example, the  $> 73$  MWh -  $\leq 14,653$  MWh capacity charge (c/pk day kWh) for 2023-24 is  $150.3134 - 4.3699 * \ln(\text{MDQ})$ . Smaller and larger sites do not have an MDQ input.

Figure 17:  $\leq 73$ MWh gas distribution charges. October – October charging year



Source: Cornwall Insight, [CRU](#)

# Natural Gas Carbon Tax

## Natural Gas Carbon Tax

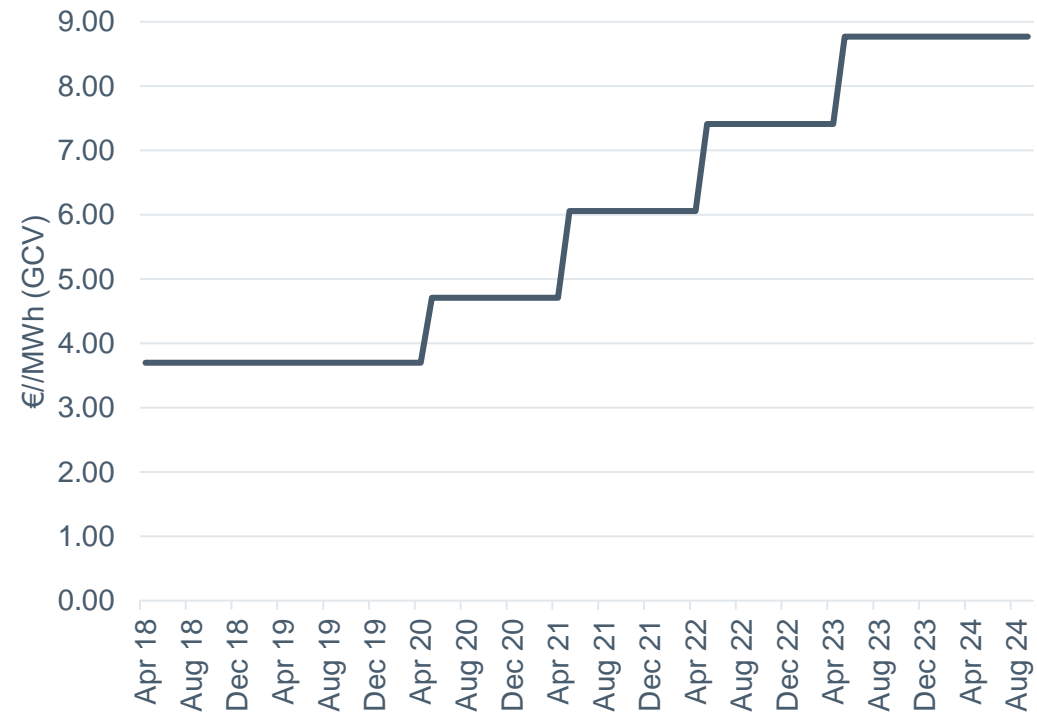
### Summary of recovery

The Natural Gas Carbon Tax is recovered from gas suppliers on a €/MWh basis. The rate of NGCT is proportionate to the amount of carbon dioxide emitted when natural gas is combusted.

Different rates apply based on whether the supply is measured at Gross Calorific Value or Net Calorific Value (conversion rate made available).

Exemptions apply to usage purposes including or electricity generation (not including CHP)

Figure 18: Natural Gas Carbon Tax rates at Gross Calorific Value



Source: Cornwall Insight, Revenue

# 5. Historical electricity and gas costs for demand users



# Archetypes

The following customer archetypes have been used to produce indicative charges for electricity and gas. These are based on published figures and our understanding of typical characteristics of domestic, small/medium businesses, and large businesses

## Electricity archetypes

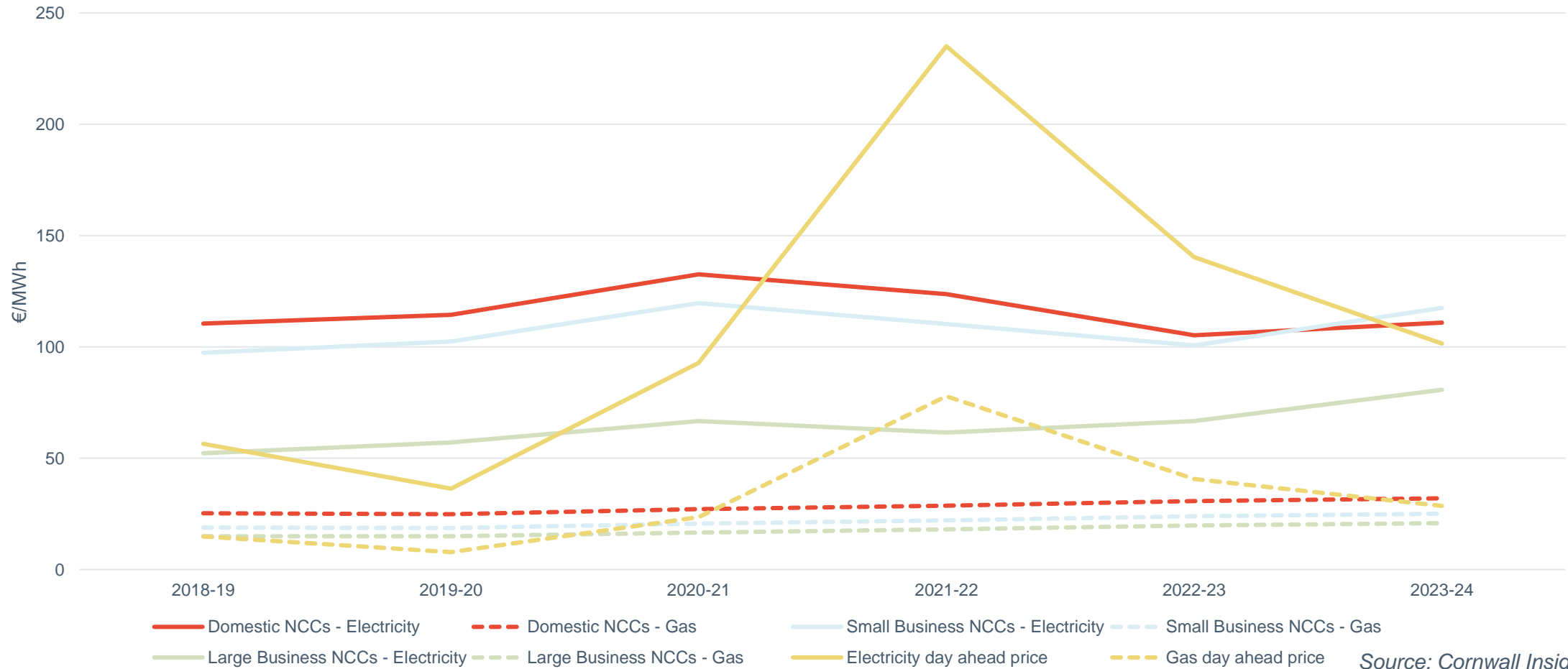
Customer archetype	Annual consumption (kWh)	Annual consumption in MWh	Maximum Import Capacity (kVA)	DUoS charging band	Day/Night		Day/Night/Peak		
					Day	Night	Day	Night	Peak
Domestic	4,200	4.2	12	Domestic (urban)	87.38%	12.62%	63.18%	12.62%	24.20%
Small/medium business	260,000	260	150	DG6	86.09%	13.92%	77.94%	13.92%	8.15%
Large business	1,250,000	1,250	550	DG9	65.02%	34.98%	57.48%	34.98%	7.54%

## Gas archetypes

Customer archetype	Annual consumption (kWh)	Annual consumption (MWh)	Peak day consumption (MWh)
Domestic	11,000	11	0.09
Small/medium business	515,000	515	2.82
Large business	1,765,000	1,765	6.29

# Overview of annual non-commodity costs – delivery year

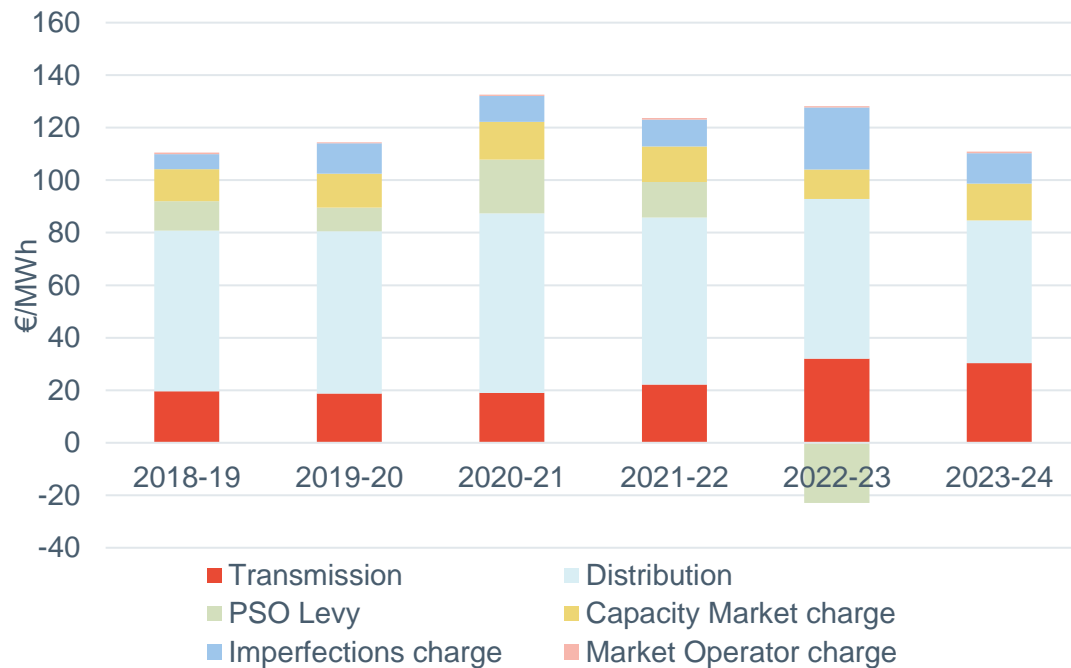
Figure 19: Overview of annual non-commodity costs and electricity wholesale prices, €/MWh basis, October-October year, 2023-24 prices



# Domestic cost breakdown – delivery year

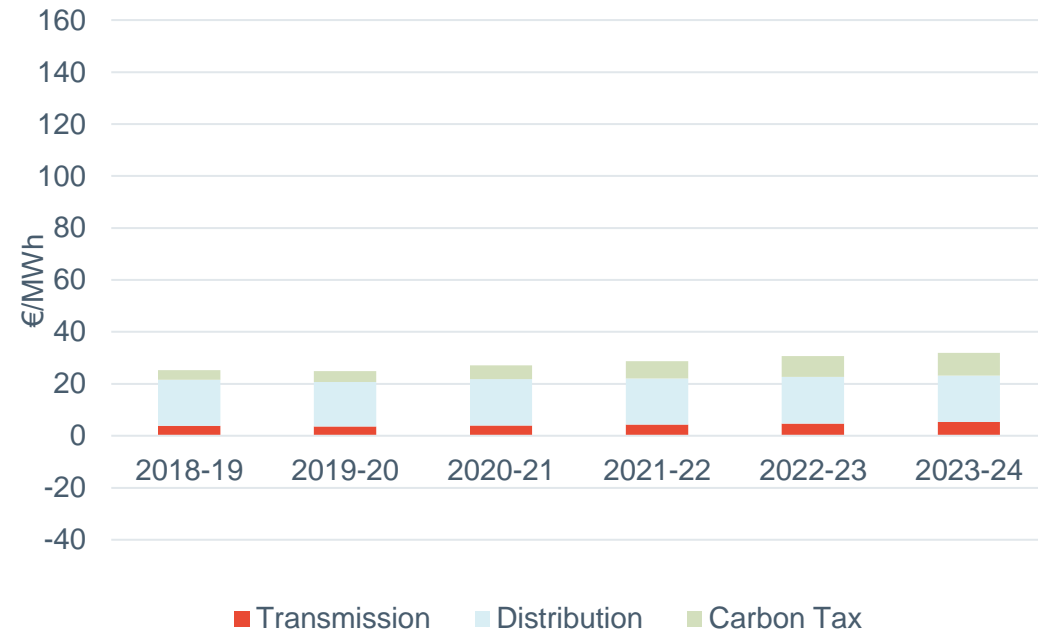
The charts below show a cost breakdown for a domestic archetype, for each October - October year. After a significant rise in the 2022-23 charging year, electricity transmission charges fell in 2023-24, while there was a small decrease in electricity distribution costs for the third year in a row. Lower DUoS costs in recent years reflect the CRU's decision to reconcile the 2010 decision to rebalance network tariffs in favour of LEUs, the savings from which were funded by domestic network tariffs. Domestic consumers are compensated in the 2023-24 delivery charging year. The negative charge in the PSO levy is shown in scheme year 2022-23, with the charge for the 2023-24 scheme year set to zero (rather than a rebate), which is intended to provide more stability in the charges ahead of an expected increase next year.

Figure 21: Electricity, 2023-24 prices



Source: Cornwall Insight

Figure 22: Gas, 2023-24 prices

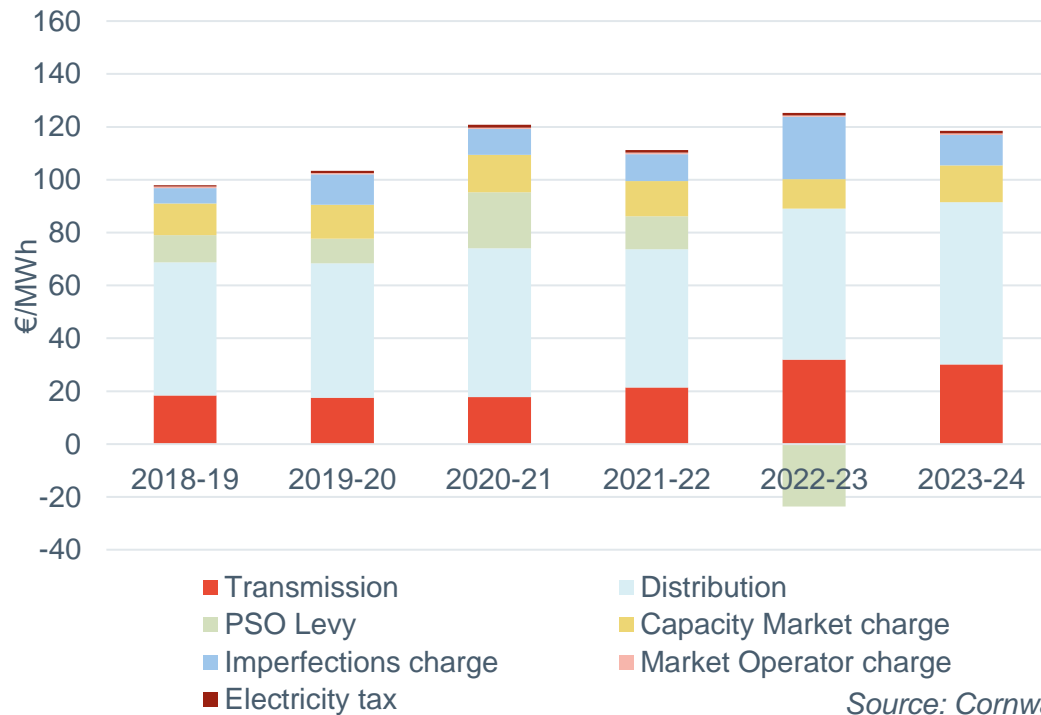


Source: Cornwall Insight

# Small/medium business cost breakdown – delivery year

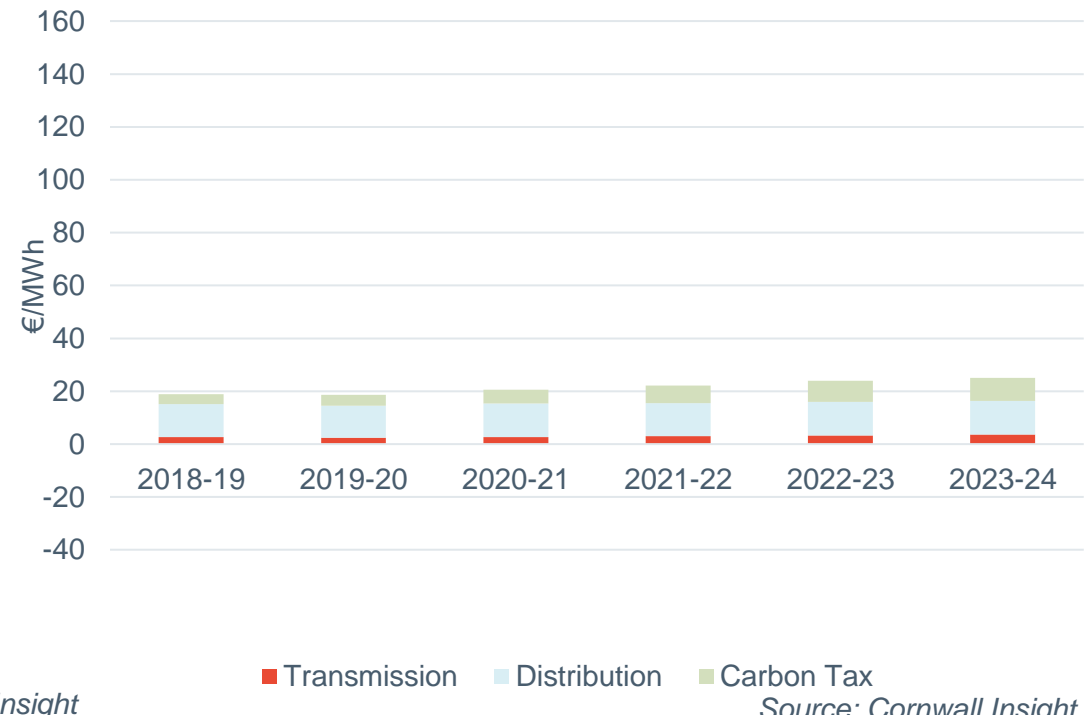
The small/medium business archetype sees an increase in electricity and gas non-commodity costs in 2023-24. While gas has steadily increased over time, notably due to the rising carbon tax, electricity costs have fallen (in real terms) in a number of areas, but overall costs are up due to the switch in PSO Levy rates from a rebate to a zero charge. There was a step up in electricity transmission tariff charges in 2022-23 across all user groups, partially reflecting increases in the system services charge within TUsS, but charges have fallen in real terms in 2023-24, although this is only due to the increase in tariffs being outpaced by inflation.

Figure 23: Electricity, 2023-24 prices



Source: Cornwall Insight

Figure 24: Gas, 2023-24 prices

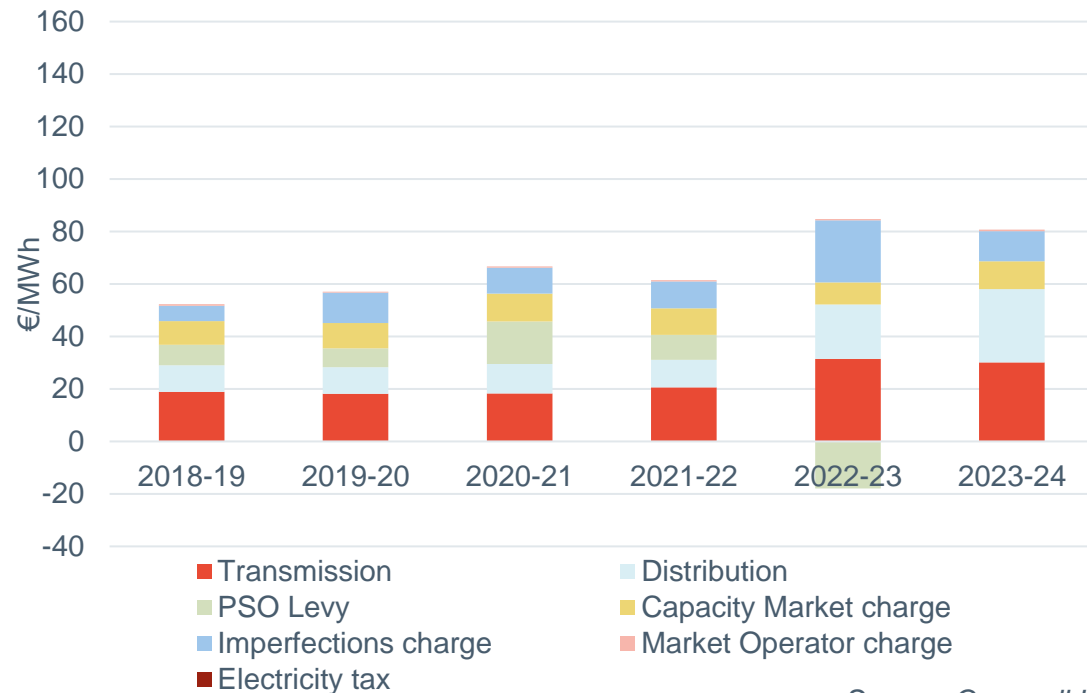


Source: Cornwall Insight

# Large business cost breakdown – delivery year

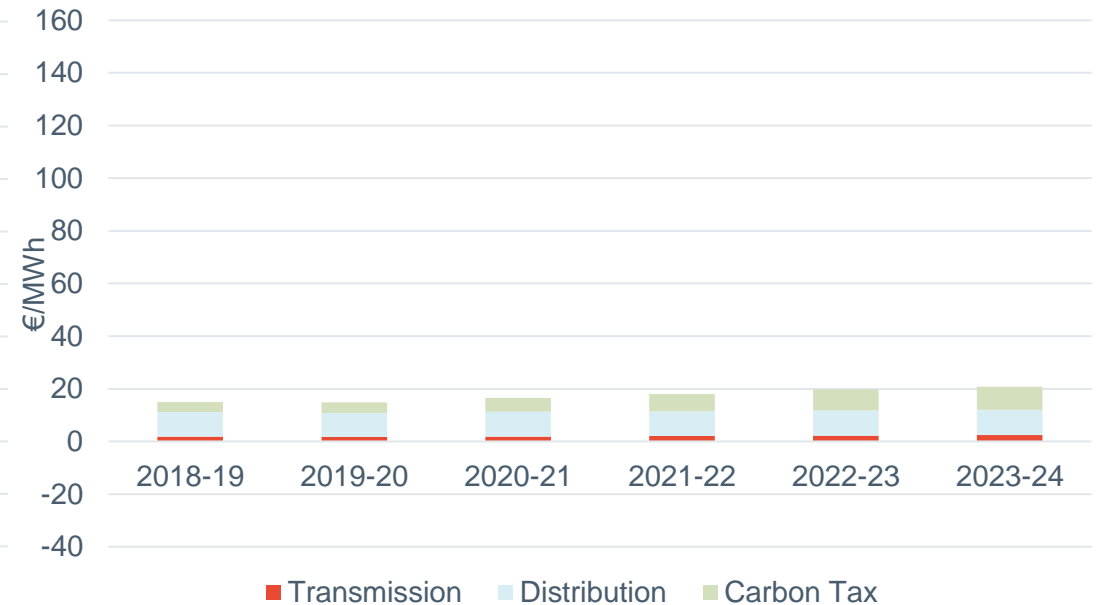
Large businesses have seen a real terms increase in non-commodity charges in 2023-24. The biggest individual rise stems from an increase in electricity distribution charges, from €20.71/MWh to €27.94/MWh. This reflects the CRU’s decision to reconcile the 2010 decision to rebalance network tariffs in favour of LEUs, the savings from which were funded by domestic network tariffs. Following impact analysis in 2021, the CRU has ceased the rebalancing arrangements from 1 October 2022, and applied a correction for all affected customer groups from 1 October 2023. While domestic consumers are compensated in the 2023/24 tariff year, the associated increase in LEU tariffs will be smoothed over a three-year period from 2023/24 to 2025/26. The increase in overall electricity costs is also partly due to the PSO levy switching from a rebate to a zero charge.

Figure 25: Electricity, 2023-24 prices



Source: Cornwall Insight

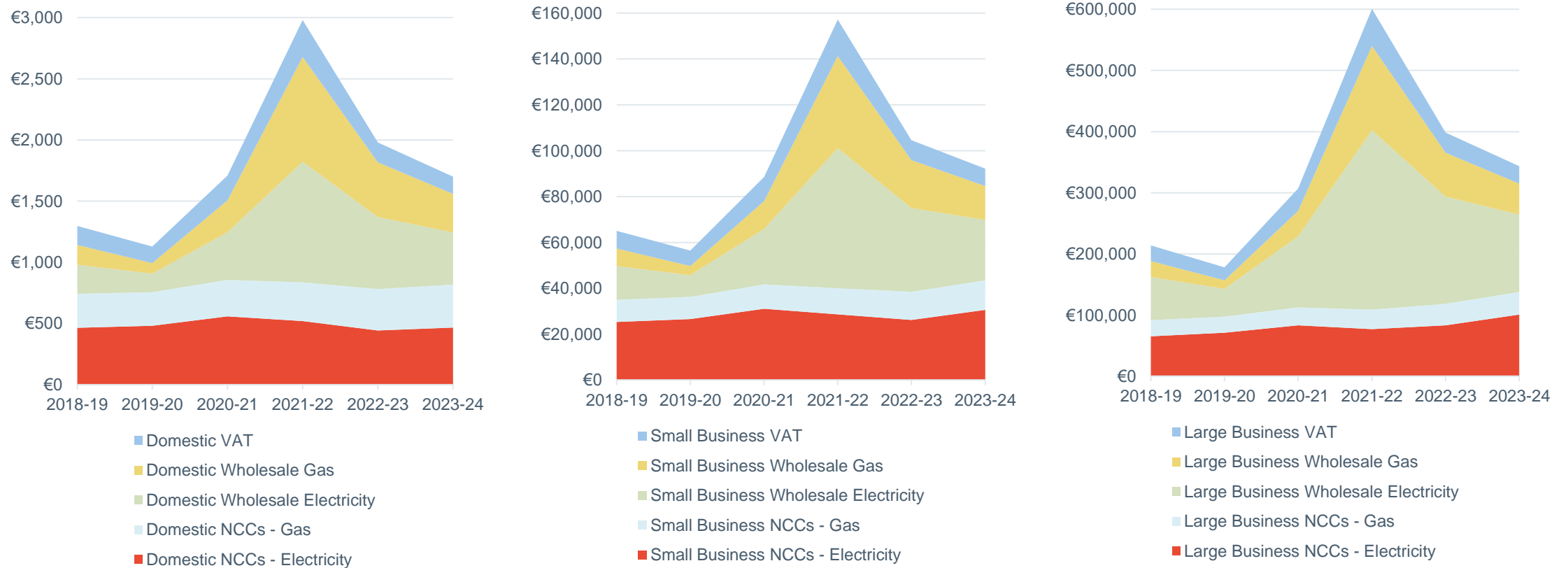
Figure 26: Gas, 2023-24 prices



Source: Cornwall Insight

# Overview of total annual non-commodity costs – delivery year

Figure 27: Total annual non-commodity costs and wholesale prices (indicative based on day-ahead prices) by customer archetype, October-October year, 2023-24 prices\*



\*We note the cost stack outlined does not include supplier costs, estimated to be around 2% of the overall bill

Source: Cornwall Insight

# 6. Exemptions



# Exemptions

We have identified a limited number of exemptions from elements of the cost stack for consumers. Many of these are temporary, and were introduced in response to high energy prices. We do not expect that any of the measure identified would have a positive or negative influence on the electrification of heat

- In response to high energy prices, the Electricity Costs Emergency Benefit Scheme (3) was announced in the Budget 2024. Domestic electricity customers received €450 off their electricity bills, paid in three energy credit instalments of €150. The last credit was made between 1 March and 30 April 2024
  - The support is a reduction on the electricity bill, deemed to be fairer than delivering the gas bill as there are more users connected to the electricity network. As this is a temporary benefit, we don't expect it to have an influence on choice of heating fuel in the longer term
- The Temporary Business Energy Support scheme provided a similar scheme for businesses. A business could make a claim under the scheme if it was tax compliant, was a company where the profits are chargeable to tax under Case I or case II of Schedule D by virtue of section 18(2) of the Taxes Consolidation Act, 1997 (TCA), and had seen the average unit price for electricity or natural gas on the relevant bill increase by 30% or more as compared to the average unit price 12 months prior to the claim period. The claim was equal to 30% of a business' eligible costs for September 2022 to February 2023, and 50% of businesses eligible costs for March 2023 to July 2023 periods, subject to a monthly cap
  - This measure passed through a reduction on both gas and electricity bills, and therefore did not provide an incentive for either fuel. It was also a temporary measure, and not expected to remain in place over the longer term
- Since May 2022, the rate of VAT on gas and electricity bills has been reduced from 13.5% to 9%. This lower rate is in place until 31 October 2024
  - The rate reduction impacts gas and electricity equally, so provides no longer term incentive influencing choice of fuel
- The Department of Social Protection provides guidelines to administer schemes comprising the Household Benefits Package, including an Electricity/Gas allowance. This is a €1.15/day allowance provided as credit on a bill or cash, against electricity or natural gas. The scheme is available to those aged 70 or over residing in Ireland and a registered consumer of electricity/gas (not means tested), and is also available to those aged under 70 years who meet qualifying criteria
  - The scheme supports energy users across electricity and gas, and is therefore not expected to influence choice of heating fuel in the longer term

# 7. Risk register



# Understanding risk

- We have carried out the following analysis to understand the risk around future charges:
  - Changes or variability in currently existing charges
  - New charges or new components added to charges in the future
- For each of these we have set out:
  - Description: What is being proposed?
  - Timescale: When to we expect the change to be implemented?
  - Materiality: Extent or magnitude of impact of the risk on customer bills; scored as per the RAG key below
  - Commercial considerations: Considerations in the context of the cost stack and electrification of heat

*RAG score key:*

Score	1	2	3
Key	Low	Medium	High

# Risk register (1)

Risk	Description	Timescale	Materiality	Commercial considerations
<b>Supporting renewable energy targets for 2030 (80% RES-E in generation mix) and beyond</b>	<p>The Irish government has ambitious targets for decarbonisation, including the continued deployment of renewable generation.</p> <p>The PSO levy is charged or credited to all electricity customers and recovers funds that support renewable generation, currently the REFIT and RESS.</p> <p>As additional renewable capacity is deployed to meet decarbonisation targets the expected cost of PSO will increase (subject to movements of the wholesale price). In the near term as wholesale electricity prices are expected to decrease to the mid-2030s this indicates the cost of the PSO will increase.</p>	Ongoing – RESS/ORESS support can continue up to 2045-2050 and potentially beyond if projects commission post 2030	<p><b>2</b></p> <p>The PSO levy has to date been significantly lower than network costs and in recent years represented a credit to customers.</p> <p>However, due to its reference to the wholesale power price (and to a lesser extent the continued build out of assets under the RESS) the PSO has a considerably higher level of volatility than other non-commodity costs.</p>	Given forecast falls in wholesale electricity prices and continued deployment of renewable capacity under the schemes the level of the PSO is likely to increase, although remain relatively low compared to other non-commodity costs such as network charges.
<b>Reduction in REFIT costs</b>	<p>The <u>REFIT scheme</u> provides renewable assets with a one-way contract for difference (CfD) for 15 years. The scheme ended in 2015 to new generation, and the costs of the existing contracts are expected to reduce over time as they roll off, with backstop end dates arising from 2027 to 2030.</p> <p>This will reduce some of the input costs to the PSO Levy over time. The REFIT scheme cost €10.39mn in 2023/24 compared to RESS cost of -€59.4mn.</p>	Ongoing to 2030	<p><b>2</b></p> <p>There will be a reduction in the inputs to the PSO Levy over time, although this may be offset by increased rounds of RESS further building additional capacity</p>	As above, as the volatility in the PSO Levy will remain with increased RESS projects operating on a two-way CfD

# Risk Register (2)

Risk	Description	Timescale	Materiality	Commercial considerations
<p><b>Increased network charge costs due to offshore element adding to D-TUoS</b></p>	<p>The CRU issued a <u>consultation</u> in March 2024 on the arrangements for offshore grid charging policies.</p> <p>As part of this it is seeking views on how to recover the costs of offshore transmission assets constructed by EirGrid for Phase 2 assets.</p> <p>Two options are proposed. Under option 1, the costs of offshore transmission assets would be recharged to offshore generators through an Offshore Generator Transmission Use of System (OG-TUoS) being consistent with Phase 1 projects. Under the option 2, the costs of offshore transmission assets would be socialised across all electricity consumers through D-TUoS tariff.</p> <p>The CRU noted it does not have a preferred option</p>	<p>Charge to apply from <b>2027 at the earliest</b></p> <p>Decision expected Q324</p>	<p>2</p> <p>The exact impact of the change is to be determined as the charging methodology specifics are still to be confirmed.</p> <p>However, in the consultation CRU suggested that option 2 would result in an increase of €7-10/yr for an average household based on phase 2.1 offshore assets. This would represent a ~10-15% increase for the network charging element</p>	<p>Under option 1 consumers would not face any additional direct costs (although offshore generation costs would be expected to be higher to reflect the costs and so result in a higher wholesale price).</p> <p>Under option 2, the costs of the assets would be socialised over all customers resulting in a direct increase in network costs.</p> <p>Despite the relatively limited annual increase estimated for phase 2.1 assets, we note this is for 900MW capacity. Given the Irish government's target to install 5GW by 2030, further increases may result.</p> <p>We note that for Phase 1 projects (which were developer rather than plan led) saw the cost levied on the generators (i.e. option 1) but given the difference in phase and development type this may not indicate the expected outcome.</p>

# Risk register (3)

Risk	Description	Timescale	Materiality	Commercial considerations
<b>Renewable Heat Obligation for gas</b>	A new <u>obligation</u> on suppliers of heat to include a proportion of supply from renewable sources. The initial rate is expected to be set at 0.5% and rise to at least 3% over the decade. Currently proposed to impact all providers of oil, LPG, natural gas, coal and peat. It is not currently proposed to include electricity supplied for heat, although this has been raised as a question in the latest design consultation. We expect costs to be passed back through to consumers through their heat supplier	Design of the obligation was consulted on in October 2023, with implementation expected from 2024 and scaled up over time	2 Year 1 (2024) of the scheme is expected to cost equivalent to around €4-€9/year for a household depending on consumption. This rises to €24-€54/year by 2030. For I&C consumers, this ranges from <0.7%-<1.5% of the bill in year 1 to <3%-6% of the bill in 2030	Likely to add additional costs onto to gas bill (or equivalent non-electricity heat bill), incentivising electricity usage in heat
<b>Changing chargeable demand levels</b>	The level of demand (both overall and peak) on the system impacts the charging basis of non-commodity costs and therefore their individual value level for consumers.  As part of the move to net zero, overall electricity consumption is expected to increase – due to the electrification of demand sources such as transport and industrial heat. This will increase the level of demand on the system, and assuming all other factors remain the same, spread non-commodity costs over a larger charging base.	Ongoing – expected to become increasingly significant from the 2030s	1 The increase in demand as part of decarbonisation is expected to be relatively slow and unlikely to materially change the charging basis until the 2030s.	During this period wider changes are expected to have a larger impact on non-commodity costs than the changing demand base.

# Risk register (4)

Issue	Description	Timescale	Materiality	Commercial considerations
<b>Future Arrangements for System Services (FASS)</b>	<p>FASS will replace the current DS3 procurement approach for balance services (e.g. frequency reserve and voltage support services). DS3 operates on a regulated tariff basis, while FASS will move to competitive auction arrangements.</p> <p>FASS costs will replace those currently seen under DS3 on consumer bills as part of the System Services charge included in TUoS.</p>	December 2026 for the initial FASS auctions	<p>1</p> <p>The move to FASS is not expected to materially impact the level of cost of System Services in TUoS. The change to competitive auctions may lower the cost of individual schemes (although increased service needs as the system decarbonises will balance this). The charge is currently a flat charge, and we expect this may change to a per kWh for transmission usage at the trading point</p>	The move to FASS from DS3 is not expected to materially alter end user bills. However, under a competitive procurement arrangement service costs are more likely to vary in response to input costs and competition levels which may have forecasting the cost more complex.
<b>Procurement for Long Duration Energy Storage (LDES)</b>	<p>EirGrid is <u>exploring</u> potential procurement methods to provide a sufficient incentive for its LDES. Responses to a call for evidence have been published in March 2024, outlining requirements and interactions with other market challenges.</p> <p>Payment methods are being modelled, including proposals for a “floor and share” mechanism would see a fixed portion of revenues earned above the floor returned to consumers, keeping overall costs lower</p>	At the latest by 2029	<p>1</p> <p>It is not possible to forecast the exact cost at this time as the exact methodology and level of support provided is still to be determined.</p> <p>We would expect that the cost impact will be relatively limited and is expected to be materially lower than renewable support costs incurred to date.</p>	LDES support schemes will introduce a new subsidy cost to be recovered from consumers. However, the level of this is expected to be relatively low, and will be at least partially offset by the wider system benefits LDES brings to lower balancing actions etc.

# Risk register (5)

Risk	Description	Timescale	Materiality	Commercial considerations
<p><b>Unrealised Available Energy Compensation (UAEC)</b></p>	<p>UAEC will be a payment in addition to the RESS support. It will be paid where a RESS project has the availability to generate, but is dispatched down for a reason other than transmission constraint.</p>	<p>Applicable once RESS and ORESS 1 assets are energised, which may be around 2025 at the earliest</p>	<p>1</p>	<p>This will introduce a new payment to RESS supported assets. However, it is expected to drive bid prices down compared with previous auctions given developers will be protected in dispatch down scenarios. Overall on a net basis the impact is therefore expected to be minor</p>

# Contact us

Anna Moss

Senior Consultant



+44 (0) 7741 647 882



[a.moss@cornwall-insight.com](mailto:a.moss@cornwall-insight.com)