November 2026

2026 Thermal constraints update



NESO
National Energy System Operator

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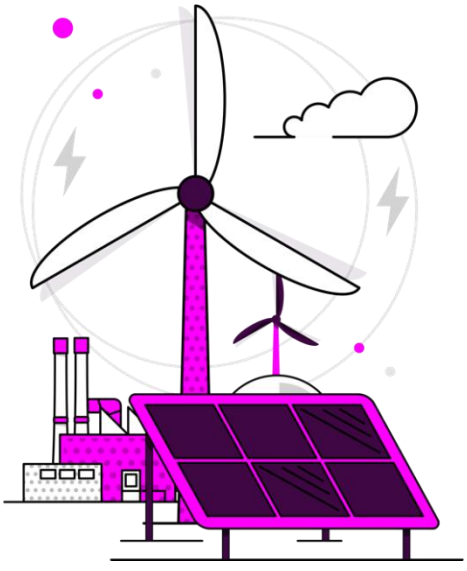
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2026 Thermal Constraints Update



Foreword



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As Great Britain's electricity system continues to grow and evolve, balancing costs are an increasingly important area of focus for NESO, industry and policymakers alike. The conclusions of this year's assessment are broadly consistent with those set out in last year's balancing cost report. Thermal constraint costs are expected to become increasingly challenging over the coming years, remaining elevated until major network reinforcements are delivered. These costs are ultimately borne by consumers, making it vital that we continue to improve our understanding of what drives them, how they may change in future and where action can deliver the greatest value.

Thermal constraints remain the most significant contributor to balancing costs. They are a visible consequence of a wider challenge facing the energy transition: ensuring that generation, demand and network infrastructure develop in a coordinated way as our electricity system decarbonises. While some level of congestion is efficient, Great Britain's generation infrastructure has outpaced network build over the last 15 years, resulting in sustained high congestion.

Addressing this challenge requires close collaboration across government, Ofgem, Transmission Owners (TOs), NESO and wider industry. Existing efforts are already delivering benefits: Working with our partners, we saved £430m of thermal constraint cost in 2025/26 by making better use of existing network infrastructure, expanding the tools available to manage constraints and increasing access to lower-cost market-based solutions. Building on this progress, we will continue to work with our partners to minimise costs while supporting a secure and reliable electricity system.

This report sets out NESO's latest assessment of how thermal constraint costs could develop over time and the factors that influence them. While future outcomes will depend on how underlying assumptions evolve, our projections highlight the key drivers of future costs, the challenges that lie ahead and the opportunities to deliver value for consumers.

We hope the report, together with the accompanying Technical Annex, provides a useful contribution to that conversation and helps build a shared understanding of the actions needed to support a more efficient electricity system.

Headlines

1. **The objective is lower consumer costs, not simply lower constraint costs**
   - The lowest constraint-cost system is not necessarily the lowest-cost system overall. Actions that reduce constraint costs can also increase costs elsewhere in the electricity system, meaning lower constraint costs do not always result in lower overall costs for consumers.
   - Together with industry partners, we are helping ensure that opportunities are assessed according to their overall value for consumers, recognising that proposals may create costs or benefits elsewhere in the system.
2. **Delivering network reinforcement remains the single most important lever for reducing future constraint costs**
   - Our modelling continues to show that significant and enduring reductions in constraint costs depend on new network infrastructure being delivered.
   - We are working with Transmission Owners (TOs)[1] through initiatives such as System Access Reform to help enable timely and efficient network delivery, to coordinate and optimise outage planning, and to maximise the benefits and consumer value delivered by network investment.
3. **The largest long-term opportunities lie in strategic planning and market reform**
   - Future constraint volumes are driven by mismatches between where electricity is generated, where it is needed, and when network capacity becomes available.
   - Further, in areas of regional supply and demand imbalance, distorted wholesale price signals incentivise providers to exacerbate constraints.
   - Together with our partners, we are addressing these challenges through longer-term initiatives such as the Strategic Spatial Energy Plan and Centralised Strategic Network Plan, while exploring potential reforms to market, dispatch and investment arrangements through Reformed National Pricing (RNP).
4. **We are already taking action to enable more cost-effective constraint management through operational improvements and more flexible markets**
   - Constraint volumes are projected to remain significant as the electricity system grows, but there are opportunities to minimise the cost of managing them.
   - The actions we are taking with TOs to make better use of the existing network are already delivering results, with around £430m of realised constraint cost savings in 2025/26.
   - Through initiatives such as the evolution of the Demand Flexibility Service and Demand for Constraints, we are expanding the role of flexibility in constraint management, enabling new flexible assets to compete in balancing markets.

The following sections explain why thermal constraint costs matter, what the latest projections tell us, and the priorities for reducing costs over the near, medium and longer term. Supporting detail is provided in the accompanying Technical Annex.

[1] National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT) and Scottish & Southern Electricity Networks Transmission (SSEN)

Thermal Constraint Costs and Consumer Impact

What are thermal constraints?

Thermal constraints occur when the transmission network cannot safely transport all the electricity that would naturally flow between different parts of Great Britain (GB). They reflect the physical limits of network infrastructure and the need to operate the electricity system securely.

Thermal constraint costs arise from a combination of interconnected factors operating across different timescales. These can be grouped into three key drivers:

- **Regional Supply and Demand Imbalance:** the extent to which local electricity supply and demand are balanced. Where generation and demand are not aligned within a region, electricity must be transferred elsewhere on the network.
- **Insufficient Network Capacity:** the extent to which the transmission network can safely transport electricity between regions. Where required power flows exceed available capacity, constraints arise.
- **Redispatch Costs:** the cost of the actions taken to manage constraints when electricity cannot be transported to where it is needed. These actions typically involve reducing generation or increasing demand in one location, while increasing generation or reducing demand elsewhere to maintain system security. The cost of these balancing actions contributes to thermal constraint costs.

These drivers work together. Regional imbalances create a need for electricity to flow across the network. Where network capacity is insufficient to support those flows, we may need to reduce generation in one location and increase generation or demand elsewhere to maintain system security. Managing constraints requires us to take balancing actions, sometimes called redispatch, which is where the associated costs arise.

GB currently operates a national wholesale electricity market. As a result, wholesale prices do not fully reflect local network constraints, meaning market outcomes do not always align with the physical constraints of the network. In some cases, this can increase the need for redispatch actions to maintain system security.

This is particularly relevant for interconnectors, whose flows are driven by wholesale market prices rather than local network conditions. As a result, interconnector flows may not always align with the needs of the transmission network and can contribute to the need for additional redispatch to manage congestion.

A detailed framework on the three drivers is provided in the Technical Annex.

What does this mean for consumers?

Thermal constraints were the largest component of balancing costs in 2025/26, accounting for around 65% of the total, equivalent to ~£2bn. Constraint costs have remained elevated during 2026, with higher gas prices among the factors contributing to higher redispatch costs. Sustained higher gas prices could therefore contribute to constraint costs remaining elevated. Further detail on balancing cost outturns and the drivers of costs in 2025/26 is set out in our Outturn Balancing Costs 2025/26 report.

During the same period, **actions that we took together with industry partners delivered ~£430m[2] of thermal constraint cost savings,** including ~£316m from initiatives designed to make better use of the existing network. While overall thermal constraint costs continued to rise, these actions reduced the costs that would otherwise have been incurred. Together with partners, we are continuing to identify opportunities to make better use of the network, to improve system operation and to enable more flexible resources to participate in constraint management.

Constraint and balancing costs, however, represent only one part of the costs ultimately borne by consumers. In 2025/26, Balancing Services Use of System (BSUoS) charges contributed around 4.3% (£41 per year[3]) to a typical domestic electricity bill, alongside wholesale electricity costs, other network costs, policy costs and other charges.

An action that reduces constraint costs does not automatically reduce the total cost to consumers. Building additional network infrastructure, for example, may reduce the need for costly constraint actions, but consumers also fund that investment through network charges. Constraint-management initiatives can involve similar trade-offs.

For this reason, investment and initiatives are assessed according to their overall impact on consumers, not simply the savings they produce in one part of the electricity system. Action should be taken where the expected consumer benefits justify the associated costs, while maintaining a secure electricity system.

Thermal Constraint Cost Projections

Our projections provide a forward-view of how thermal constraint costs could evolve as the electricity system changes. They are not predictions of annual costs; instead, they show how factors including generation and demand growth, network capability, outages and market conditions could affect the level and timing of future costs.

The projections help identify the principal cost pressures, demonstrate the importance of planned network reinforcement and indicate where action can have the greatest impact. They therefore provide an evidence base for the priorities set out later in this report.

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[2] £430m of thermal constraint savings are derived from the following initiatives: Trading; Constraint Intertrip Services; Demand Flexibility Service (DFS) and Enhanced Network Provisions (STCP11-4), which enable more electricity to flow across the existing network while maintaining system security.

[3] Based on a 2,700kWh per year usage

How were the projections produced?

The projections combine two modelling approaches to provide both a year-ahead view of thermal constraint costs and a longer-term assessment of how costs could evolve as the electricity system develops.

2027 year-ahead projection

The 2027 projection is based on a short-term operational model reflecting current market conditions, network availability, outages and system operation. It sets out our view of likely thermal constraint costs under given near-term conditions, while recognising that factors such as gas prices and operational events can still significantly influence outcomes.

2028 onwards

Projections from 2028 onwards are based on a long-term energy system model. The model uses Future Energy Scenario (FES) 2025 assumptions[4], amended to reflect Connections Reforms, for future generation, demand and flexibility, together with recommended network reinforcement assumptions informed by NESO's Beyond 2030 Electricity Transmission Update (tCSNP2 Refresh). For the period to 2030, outage assumptions are based on TOs' current best view of planned outages, although these plans remain subject to change.

The modelling uses a common set of network reinforcement and outage assumptions across all pathways. Gas price assumptions are also common across the three net zero pathways, while the Falling Behind pathway assumes lower gas prices. As a result, differences between the net-zero long-term pathways primarily reflect differences in the scale and location of generation and demand development, rather than differences in network delivery, outage programmes or fuel prices.

Scope of the analysis

The projections establish a baseline for understanding how thermal constraint costs could evolve and where planned action could make the greatest difference. They should not be interpreted as the outcome after all planned action has been taken.

In particular, the projections do not include the potential impact of any operational, strategic planning and market reform measures currently under development, including the Strategic Spatial Energy Plan (SSEP), Centralised Strategic Network Plan (CSNP) and Reformed National Pricing (RNP). Some of these measures remain at an early stage of development, while others operate at a level of detail that cannot be robustly represented within a long-term system model. Keeping these effects outside the projections provides a clear reference point against which their future benefits can be assessed.

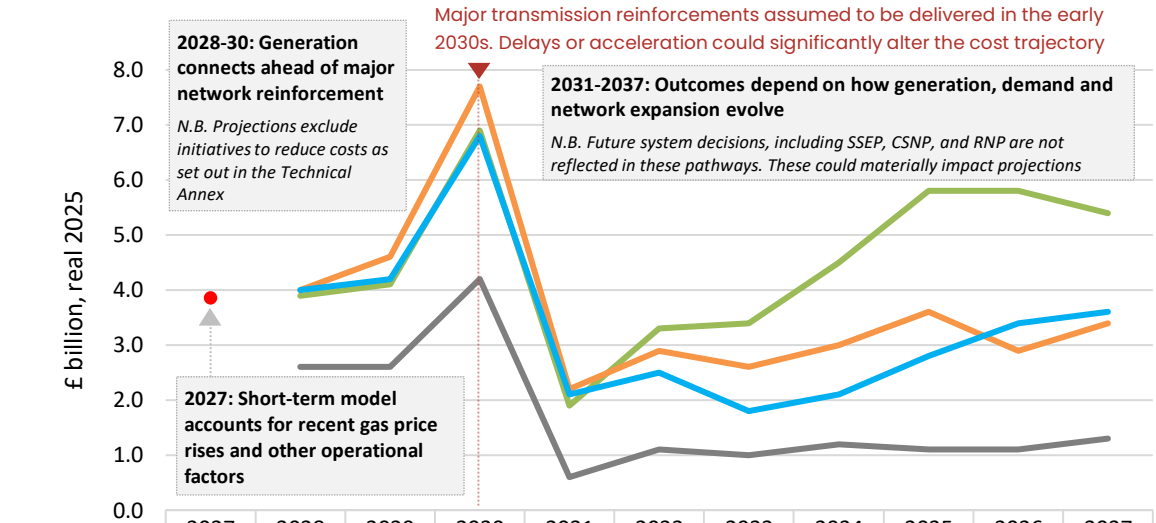
Future outcomes will also depend on factors that cannot be anticipated within the modelling, including geopolitical, policy, climate and weather developments. Interconnector flows may also change over time. These factors could affect future power flows and balancing costs, resulting in outcomes that differ from those presented here.

[4] Further details on the FES scenarios can be found in the Technical Annex.

Alongside this assessment, we are working with Ofgem to further develop our view of future constraint costs, incorporating the latest available information on expected generation connections and transmission network delivery. This work will complement the pathway analysis presented here, reflecting how these assumptions continue to evolve. We expect to publish further analysis in early 2027.

Further detail on the methodology and assumptions is provided in the Technical Annex.

Key findings from the projections



	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
HT		3.9	4.1	6.9	1.9	3.3	3.4	4.5	5.8	5.8	5.4
EE		4.0	4.6	7.7	2.2	2.9	2.6	3.0	3.6	2.9	3.4
HE		4.0	4.2	6.8	2.1	2.5	1.8	2.1	2.8	3.4	3.6
FB		2.6	2.6	4.2	0.6	1.1	1.0	1.2	1.1	1.1	1.3
Yr-Ahead	3.9										

Figure 1: Thermal constraint cost pathways under current assumptions

Year-ahead (2027): Operational factors continue to have a significant influence

- **Projected costs remain elevated due to higher gas prices reflecting recent geopolitical events and wider global gas market conditions.** Gas-fired generation often provides replacement energy during constraints, meaning higher gas prices increase the cost of redispatch.
- **Outages required to deliver network reinforcement increase projected costs in the short term.** Planned transmission outages temporarily reduce network capability and increase the need for redispatch actions but support the delivery of reinforcements that are expected to reduce projected constraint costs. Analysis shows that of the £3.9bn projected in 2027, 16% is driven by outages[5].
- **The year-ahead projection and long-term pathway projections are based on different modelling approaches**, discussed above and in the Technical Annex. The 2027 projection includes higher gas prices following geopolitical events in 2026, while

[5] Based on a comparison of model runs with and without outages, with all other assumptions held constant

projections from 2028 onwards use FES 2025 gas price assumptions, which do not reflect these events. This difference in gas price assumptions largely drives the difference in projected costs between 2027 and 2028: when the gas price assumptions are aligned, the 2027 projection is broadly consistent with the 2028 Falling Behind pathway.

Medium-term (2028-2031): The delivery of network reinforcements is a key lever for reducing costs

- **Constraint costs are projected to significantly increase across all pathways towards 2030.** The three net zero pathways exhibit a similar medium-term trajectory, with projected costs peaking at between £6.8bn and £7.7bn in 2030. This variation reflects differences in generation and demand assumptions which are explained further in the Technical Annex. The Falling Behind pathway follows a lower trajectory, reflecting lower levels of generation growth and lower gas price assumptions.
- **Generation growth increases pressure on already constrained parts of the network.** Under the Connect and Manage approach, new generation can connect before all the network reinforcement needed to accommodate it is complete, contributing to the mismatch between generation and available network capacity. With significant volumes of new generation expected to connect in regions such as Scotland and East Anglia before major transmission reinforcements are delivered, congestion and redispatch requirements are expected to increase.
- **The timing of major transmission reinforcements, including projects within the Accelerated Strategic Transmission Infrastructure (ASTI) programme, plays an important role in shaping future costs**. Constraint costs are projected to rise towards 2030 as increasing power flows and outage activity place additional pressure on the network while major reinforcements are being delivered. Costs are projected to fall once these reinforcements increase network capability, although the timing and scale of this reduction remain sensitive to both network delivery and outage plans.

Long-term (Post 2031): Future outcomes depend on how generation, demand and networks evolve together

- **The location of generation and demand matters as much as the scale of their growth.** Beyond 2031, projected constraint costs are influenced by both the volume of generation and demand, but also by their location across the network, as this determines power flows, congestion and redispatch requirements. The pathways assume continued development under current market arrangements, where national wholesale electricity prices do not fully reflect local network conditions. As a result, future generation, demand and operational decisions do not necessarily evolve in ways that minimise congestion or make the most efficient use of available network capacity.
- **Network reinforcement remains a critical determinant of projected costs.** The projections remain sensitive to network delivery and delays could materially increase projected constraint costs, while earlier delivery could reduce them. The divergence between pathways demonstrates that future constraint costs depend on how generation, demand and network development evolve together, rather than any single factor in isolation.

Priorities for Reducing Thermal Constraint Costs

Thermal constraint costs are influenced by a wide range of factors, operating across different organisations and timescales. As the system operator, NESO has a unique view of how these factors combine to create costs and, ultimately, affect consumers. While we are responsible for managing constraints in real time, significant drivers of future costs also depend on actions taken by government, Ofgem, TOs, market participants and investors. The recent National Audit Office report on upgrading the electricity transmission network reinforces the importance of coordinated action to address these challenges. The priorities below reflect many of the areas highlighted in its findings and set out where we are working with partners to deliver the greatest value for consumers:

1. **Deliver the network capability needed to support a growing electricity system**

   The projections show that the period towards 2030 will be characterised by increasing congestion as generation growth outpaces the availability of new network capacity. Delivering TOs' major transmission reinforcements, particularly projects within the ASTI programme, remains critical to reducing future constraint costs. We are working with TOs through initiatives such as System Access Reform to support their delivery at pace.

2. **Improve long-term outcomes through strategic planning and market reform**

   Future constraint costs depend on how generation, demand and network development evolve together, making coordinated action across government, Ofgem, NESO, TOs and industry critical. SSEP and CSNP should be progressed at pace to support the more coordinated long-term system development. Through RNP, we need to ensure that siting and investment signals support more efficient decisions on where generation and demand locate. Government should also consider options for further dispatch reform that could better align market outcomes with the needs of the physical system and reduce the corrective actions required to maintain system security.

3. **Continue reducing the cost of managing constraints in the near term**

   While some drivers of constraint costs sit outside our direct control, network availability, outages and market conditions continue to influence near-term constraint. Building on the £430m of savings delivered in 2025/26, we are working with our partners to make better use of the network, improve outage planning and forecasting, and enable lower-cost flexible assets and other lower-cost solutions to play a greater role in managing constraints. Together, these measures can reduce the cost of managing constraints where this delivers consumer value.

Figure 2 summarises how these priorities are being translated into action, highlighting a range of initiatives at different stages of maturity. Further detail can be found in the Technical Annex.

Strategic Priority	Why this matters	Drivers Affected	Example of planned/proposed activity
Deliver the network capability needed to support a growing electricity system	Major network reinforcement is required to support a growing electricity system and reduce future constraint costs. Delivering this infrastructure, while minimising the impact of outages and congestion during the transition, is a key challenge.	• Insufficient network capacity • Redispatch costs	**Delivering future network capability:** • ASTI delivery • System Access Reform • Outage optimisation **Making better use of network capacity:** • Network topology optimisation
Improve long-term outcomes through strategic planning and market reform	Network investment alone cannot determine future cost outcomes. Strategic planning and market reforms can help ensure that generation, demand and network infrastructure evolve in a coordinated way, with market signals supporting more efficient operational and investment decisions, reducing congestion and future constraint costs.	• Supply – demand imbalance • Insufficient network capacity • Redispatch costs	**Coordinating long-term system development:** • SSEP • CSNP **Improving market and operational signals:** • RNP: - Siting and investment levers - Balancing and settlement • Dispatch Reform
Continue reducing the cost of managing constraints in the near term	The cost of managing constraints can vary significantly depending on how effectively the existing network is used. Making best use of existing infrastructure and enabling greater participation from lower-cost flexible resources can reduce costs while longer-term solutions are delivered.	• Insufficient network capacity • Redispatch costs	**Making better use of the system:** • Dynamic Line Rating • Constraint Intertrip Services • Enhanced Network Provisions • Trading improvements **Enabling more flex and efficient constraint management:** • Demand Flexibility Service • Demand for Constraints • Removal of distortions from bid prices (P462, FCL)

Figure 2: Strategic priorities for reducing thermal constraint costs and examples of activity

Reducing thermal constraint costs requires action across the range of initiatives and timeframes given above, and close collaboration across the energy sector. This means:

- network reinforcement is delivered efficiently and at pace, increasing available capacity;
- existing network capability is used more effectively;
- market arrangements better support efficient operational and investment decisions;
- generation, demand and network development are better coordinated over time; and
- constraints can be managed using a wider range of lower-cost solutions.

Together, these outcomes can help reduce overall consumer costs while maintaining a secure and reliable electricity system.

Technical Annex



Understanding Thermal Constraints

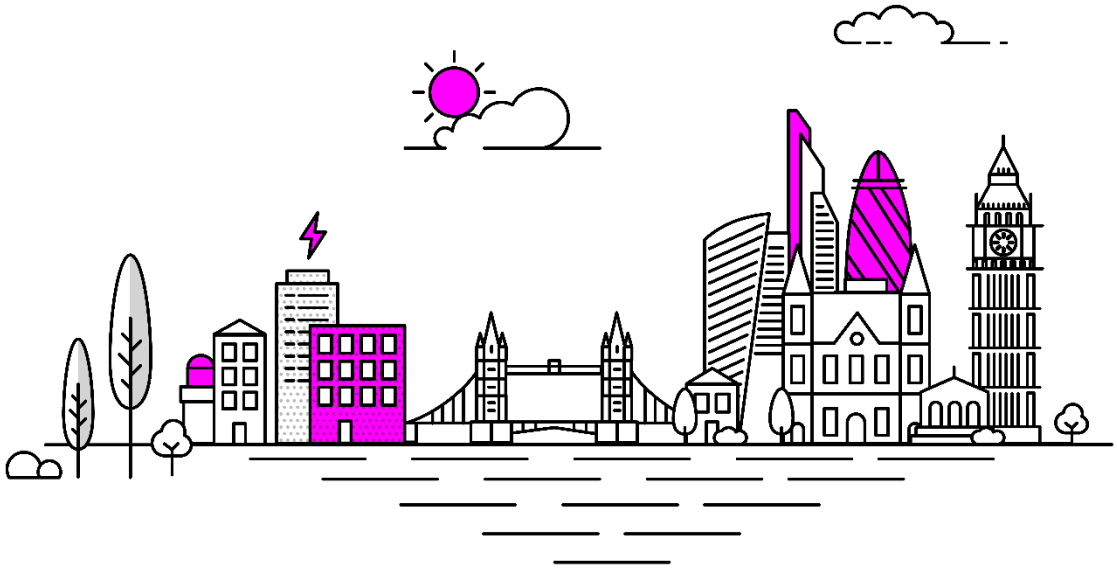
The core report explains what thermal constraints are and outlines the three underlying cost drivers. This section provides further detail on how constraints are managed operationally and the factors affecting each driver.

Drivers of Thermal Constraint Costs

Thermal constraint costs are shaped by three interconnected drivers: regional supply and demand imbalance, insufficient network capacity and the cost of redispatch.

The framework overleaf shows the underlying sub-factors that influence each driver across different timescales. Some operate day-to-day, such as weather conditions, outages and fuel prices, while others reflect longer-term changes in the energy system, including the growth of generation, changing demand patterns and network investment.

The drivers of constraint costs are highly interactive and interdependent. A surplus of power in one region can both increase pressure on nearby network capacity and create the need for redispatch in a different region. These interdependencies mean that constraint costs often cannot be cleanly attributed to a single cause.



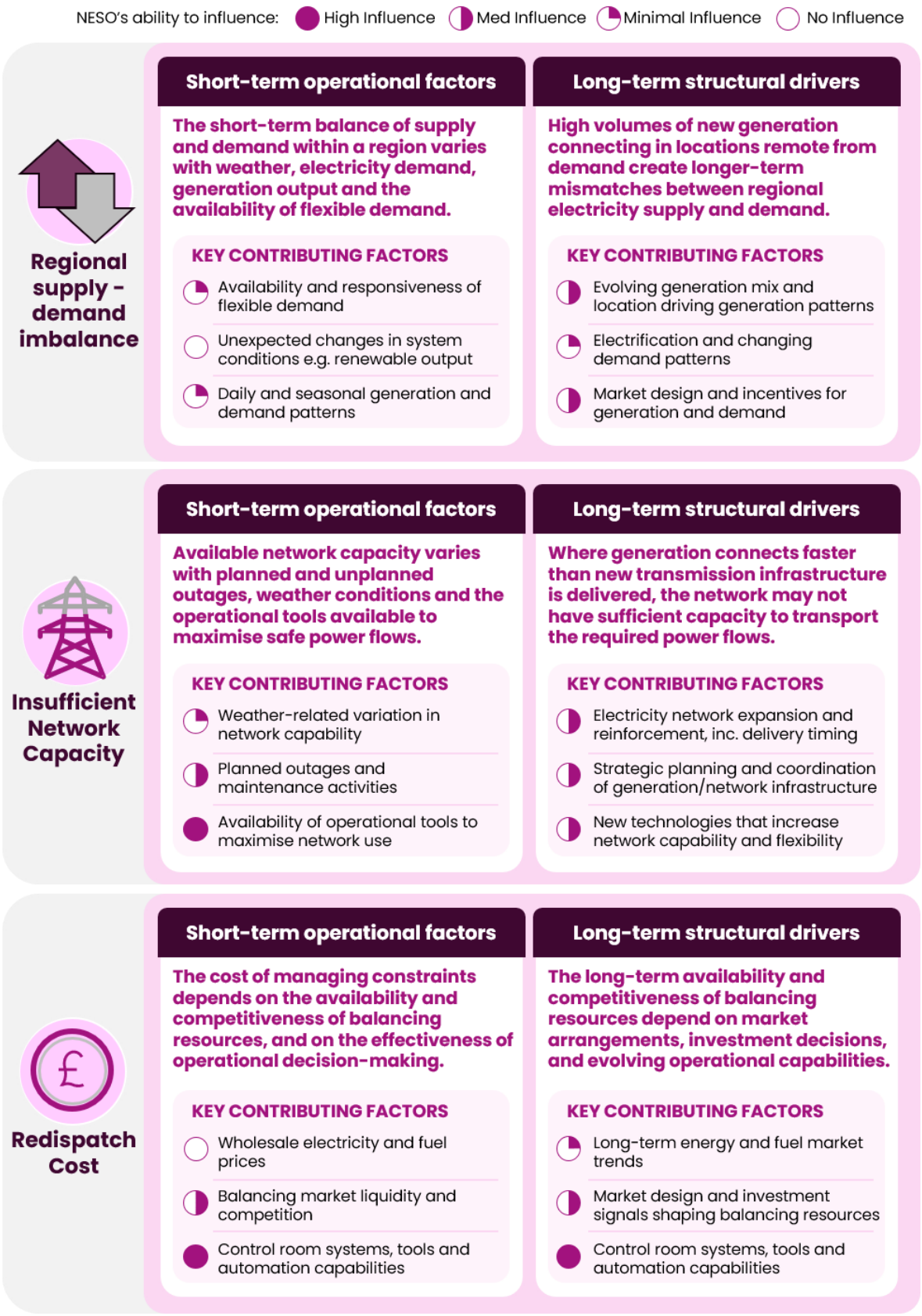


Figure 3: Short-term and long-term factors influencing thermal constraint costs

Effective constraint management requires action across all three drivers, and across both investment and operational timeframes. The framework is also used later in this annex to show how different initiatives act on the drivers to reduce costs over time.

How Thermal Constraints Give Rise to Costs

When power transfers exceed available network capacity, actions may be required to reduce generation, to increase demand or to procure replacement energy elsewhere on the system. These actions are known as redispatch and give rise to constraint costs. Redispatch costs are influenced by subsidy revenues as illustrated in Figure 4.

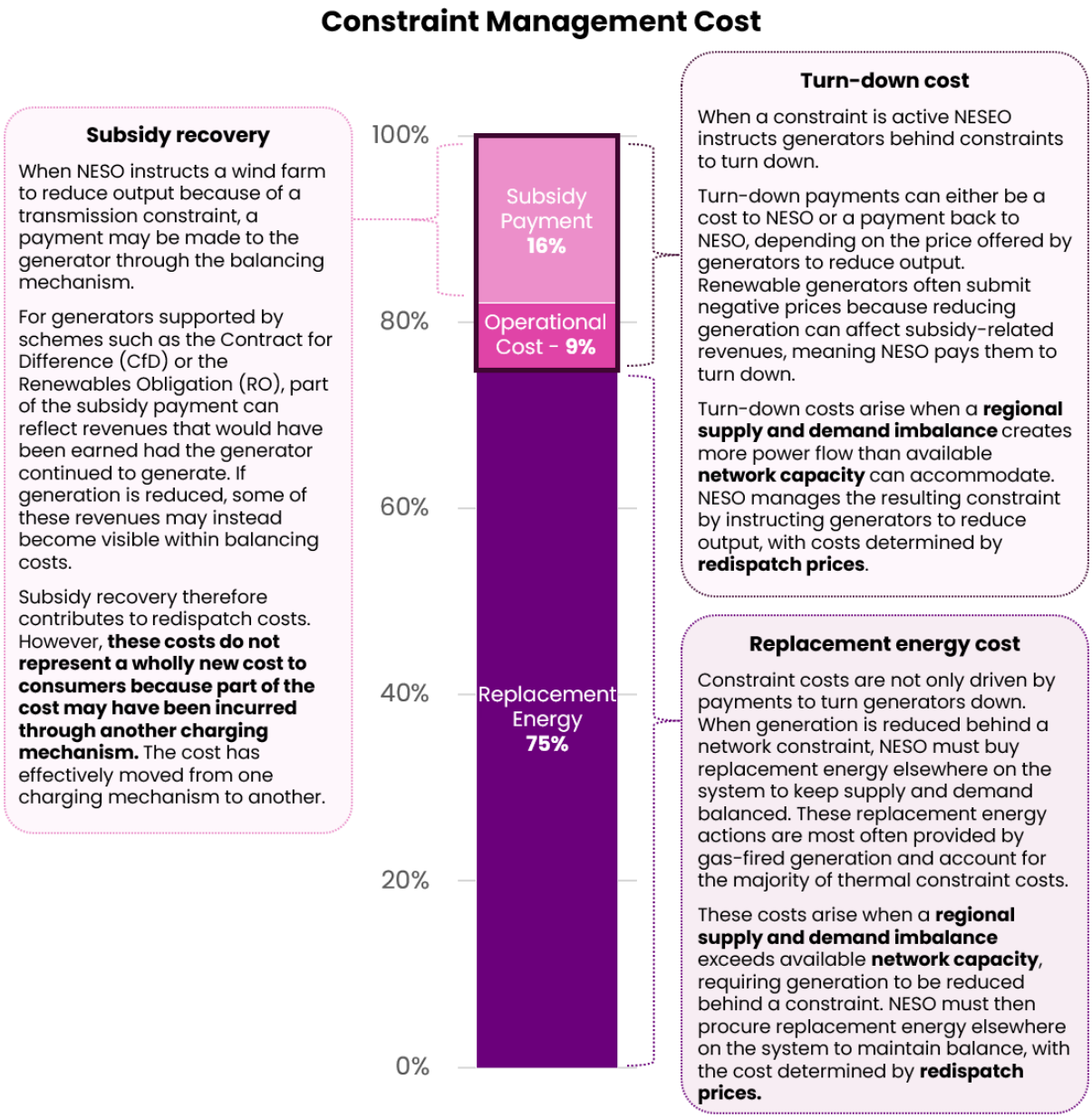


Figure 4: Illustrative components of thermal constraint costs[6]

[6] Based on 2025/26 outturn data. Turn-down costs include all curtailed wind generation volumes (subsidised and merchant) at actual bid prices. Replacement energy costs are estimated assuming all curtailed volumes are replaced at the volume-weighted average cost of replacement energy over the period. The analysis does not capture wider market effects, including the potential impact of subsidies on bidding behaviour across the market.

Thermal Constraint Costs in the Wider Consumer Cost Context

Thermal constraint costs are part of the wider costs of balancing the electricity system, which in turn represent one component of consumers' electricity bills. Assessing their impact therefore requires a whole-system perspective, recognising that an action can reduce constraint costs while increasing or reducing costs elsewhere in the system.

In 2025/26, Balancing Service Use of System (BSUoS) costs accounted for approximately 4.3% of the average domestic electricity bill, equivalent to around £41 per year for a typical household[7]. By comparison, wholesale electricity costs contributed around £206 per year and total network costs (including BSUoS) contributed around £284 per year. Figure 5 below places balancing costs, including thermal constraint costs, within the wider composition of the bill. Although BSUoS currently represents a relatively small proportion of the bill, this share could increase if thermal constraint costs develop in line with this year's projections. Its future contribution will also depend on changes in other balancing costs and components of the bill.

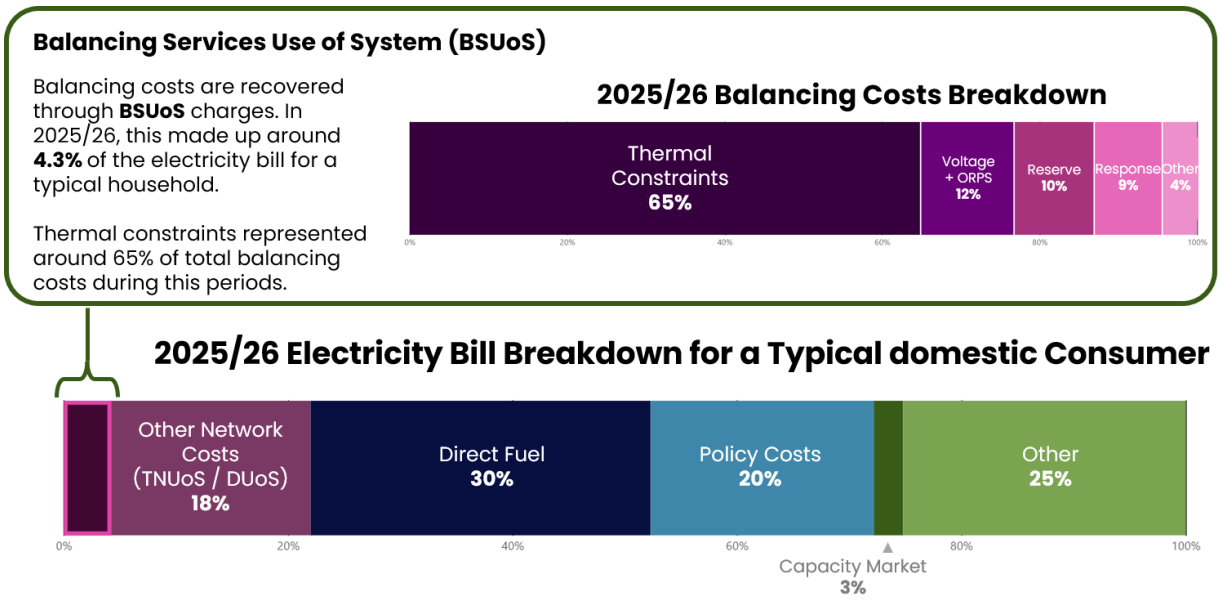


Figure 5: Balancing costs in the context of a typical domestic electricity bill, 2025/26

The same developments that affect thermal constraint costs can also affect wholesale electricity, other network, and policy costs, meaning that costs may be reduced overall or shift between different parts of the system. As Figure 5 illustrates, changes in constraints or balancing costs therefore need to be considered alongside their effects on other components of consumers' bills.

Reducing avoidable constraint costs nevertheless remains an important priority. In later sections of this annex, we set out the work underway within NESO and across industry to reduce these costs and to improve overall system efficiency.

[7] Based on a 2,700kWh per year usage

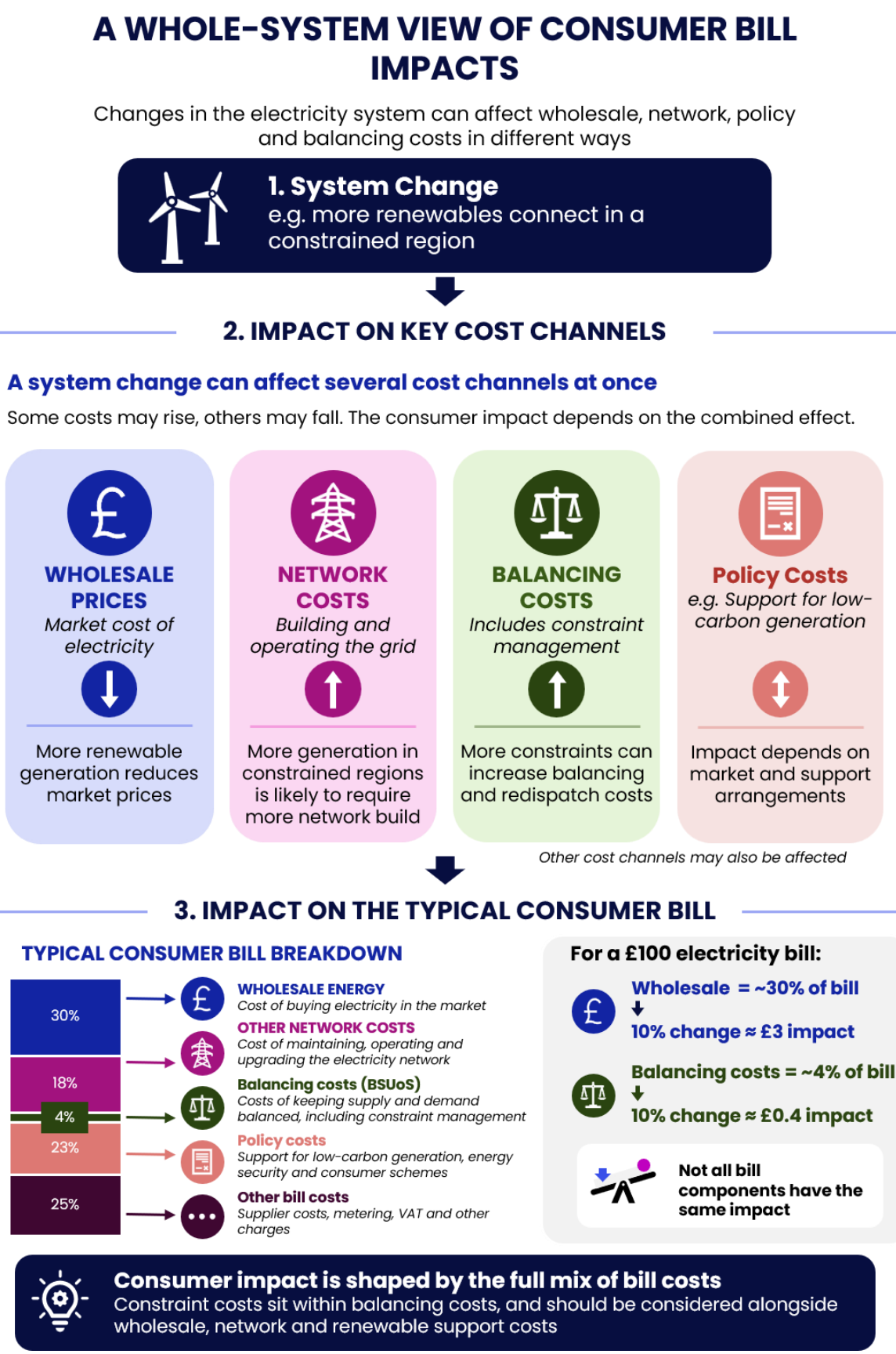


Figure 6: How system changes affect consumer electricity bills

Projection Methodology and Assumptions

Modelling Approach

The thermal constraint cost projections are produced using two complementary modelling approaches. These provide both a year-ahead assessment of likely thermal constraint costs and a longer-term view of how costs could evolve as the electricity system changes.

2027 year-ahead projection

The 2027 projection is produced using a short-term operational model designed to reflect expected near-term system conditions[8]. The model uses a detailed nodal representation of the electricity network and incorporates operational assumptions such as outage plans, commodity prices, expected market behaviour and the expected impact of existing operational initiatives and balancing tools. The model is regularly updated to reflect the latest information on system conditions and operational arrangements.

The projection reflects current expectations for market conditions, network availability and system operation, but near-term costs remain sensitive to factors such as gas prices, weather and operational events.

Long-term pathway modelling (2028 onwards)

For 2028 onwards, projections are based on a long-term energy-system model that explores how thermal constraint costs could evolve under different FES pathways. The model represents:

- future electricity demand;
- future generation, storage and flexibility resources;
- market effects such as fuel and carbon prices;
- transmission network capability;
- outage-driven reductions in network capability;
- interconnector flows; and
- the redispatch actions required to maintain system security when network constraints arise.

[8] The projections shown are an input into, rather than the output of, the BSUoS forecasting process. The BSUoS forecast applies additional statistical methods to assess how factors such as weather conditions, renewable generation output, gas prices, outages and other operational drivers have historically influenced thermal constraint costs. Those relationships are used to estimate future costs.

The modelling seeks to estimate the cost of managing constraints by simulating both the need for redispatch and the cost of the balancing actions required to maintain secure operation of the electricity system.

Key Modelling Assumptions

Future Energy Scenarios (FES)
Generation, demand and flexibility assumptions are taken from FES 2025 and adjusted to reflect Connections Reform. The pathways are intended to explore uncertainty rather than predict future outcomes.

Three pathways achieve net zero by 2050, while Falling Behind represents slower progress towards decarbonisation. All pathways assume different patterns of generation, demand and flexibility development. The three net zero pathways use common gas and carbon price assumptions, meaning differences between these pathways primarily reflect the development of future generation and demand. In contrast, Falling Behind assumes lower gas and carbon prices, as well as different generation and demand assumptions. The FES 2025 gas price assumptions do not incorporate the short-term impact of geopolitical events observed during 2026 and should therefore be viewed as long-term scenario assumptions rather than a reflection of prevailing market conditions.

Projections are influenced not only by the volume of new generation and demand, but also by the location of the buildout. Although the expected growth in generation varies by scenario, a significant share of this new capacity is in areas that are already prone to congestion. In Scotland, total installed capacity is expected to increase by 5-14GW between 2027 and 2030.

By 2035 projected electricity demand ranges from 373 TWh in Falling Behind to 433 TWh in Holistic Transition. The areas which see the greatest increases in demand are Eastern and Southern England, with the West Midlands seeing significant increases in the short term and the East Midlands seeing increases in the longer term. Wind deployment also varies significantly, reaching around 87 GW in Falling Behind compared with 125 GW in Holistic Transition.

We have recently published the 2026 10 Year Outlook, which provides our latest assessment of how electricity demand and supply could develop over the coming decade. While the 10 Year Outlook is not used directly in this modelling, its assumptions sit within the broader range of future system developments explored through the FES 2025 pathways.

Network Assumptions

Network build assumptions are based on recommendations from NESO's Beyond 2030 Electricity Transmission Update (or TCSNP2 Refresh). Building on TO delivery plans, the Refresh assesses the network needed through the 2030s and recommends how the onshore and offshore transmission system should develop.

The same network reinforcement assumptions are applied across all pathways. Differences between pathway results should therefore not be interpreted as reflecting different network delivery outcomes. Instead, they primarily reflect differences in generation and demand development. The results remain conditional on the assumed network being delivered to the timescales represented in the modelling.

Outage Assumptions

Transfer capability profiles determine how much electricity can flow between different areas of the network. For the period to 2030, capability profiles to reflect outage assumptions are based on TO outage plans and assessments of maximum secure power transfers under different operating conditions. Beyond 2030, generic outage profiles have been applied as per the tCSNP2 refresh methodology derating factor agreed with TOs, as many of the required network works have not yet been fully defined or scheduled.

Scope and Limitations

The projections are intended to support understanding of future risks, opportunities and cost drivers rather than to predict future annual costs. All pathway results should therefore be interpreted as conditional on the assumptions used within the modelling.

The analysis does not include the impact of strategic reforms and operational measures currently under development, including SSEP, CSNP, RNP and other potential interventions intended to reduce future constraints.

The modelling also simplifies certain aspects of system operation to reflect the level of granularity appropriate for long-term analysis. This includes simplifying detailed network capability and outage plans[9], as well as power-flow behaviour, some operational actions and specific market arrangements.

[9] For example, some outages are modelled at a weekly resolution and may in reality last less than a week, or common derating values may be applied across relevant circuits.

Changes Since the Previous Assessment

The long-term pathway modelling uses FES 2025 pathways, adjusted to reflect Connections Reform, and revised modelling assumptions compared to projections produced for the 2024/25 report. Changes in projected costs therefore reflect a combination of updated assumptions on gas prices, generation deployment, electricity demand, network capability and outages, rather than a single revision to the underlying methodology.

The latest projections retain the broad shape of the previous assessment, with thermal constraint costs rising towards a peak around 2030 before falling as major network reinforcements increase network capability. The highest projected peak now occurs under Electric Engagement rather than Holistic Transition, reflecting differences in the assumed scale and location of generation and demand across the updated pathways.

Key differences between the FES 2024 and FES 2025 assumptions are as follows:

- **Higher gas price assumptions increase the cost of redispatch**

  FES 2025 assumes higher gas prices than FES 2024. Across the net zero pathways, prices are on average 27% higher between 2027 and 2030 and 23% higher between 2031 and 2037. As gas-fired generation is frequently used to replace electricity that cannot be transported across a constraint, this increases the cost of redispatch and places upward pressure on projections throughout the period.

- **Changes in near-term wind deployment influence constraint costs out to 2030**

  FES 2025 generally assumes slower offshore wind deployment across the net zero pathways during the late 2020s. In Holistic Transition, short-term offshore wind capacity is on average 17% lower than in FES 2024, with the greatest slow-down in capacity being seen in Northeast England and Southern Scotland. The reduction in generation capacity in these areas behind constrained boundaries contributes to the lower projected peak for Holistic Transition in 2030.

  During the 2030s, FES 2025 assumes increased onshore wind capacity compared with FES 2024, with an average annual increase of between 21-34% depending on pathway between 2031-2037. The regions which see the greatest average annual increases are parts of Wales and Southern Scotland, with Southern Scotland having an average annual increase of between 1.3-2.6GW of capacity depending on pathway. These increases in capacity will affect flows across boundaries further south and contribute to higher projected costs later in the period.

- **Updated demand assumptions change where power flows across the network**

  FES 2025 assumes higher demand than FES 2024, reflecting greater electrification and lower assumed improvements in energy efficiency. The increase is concentrated in

areas including South Scotland, Northwest England and Yorkshire, while demand is lower in the West and East Midlands. Compared with FES 2024, this places more demand closer to generation in the north, reducing the amount of electricity that must cross constrained boundaries in Scotland and Northern England. Despite the increase in demand, its distribution across GB is expected to partially offset some of the upward pressure on projected costs before 2030.

- **Updated network and outage assumptions change the level and timing of congestion**

  For costs projected up to 2030, transfer capability profiles were updated using the latest information from TOs and network studies, replacing the generic profiles used previously with a more detailed representation of how outages and seasonal conditions affect power flows across key boundaries. These updated profiles change where and when the model identifies congestion and, consequently, lead to an increase in the volume of redispatch required.

Key Uncertainties and Sensitivities

The most significant uncertainties are summarised below. These factors may influence both the level and timing of future costs and should be considered when interpreting the projections.

The impact of policy measures

The next section sets out the wide range of work we are progressing alongside Government, Ofgem, TOs and Industry to mitigate rising constraint costs, where efficient. While implementation of proposed policy measures is uncertain, and so are not factored in the base modelling, there is significant potential for further cost reduction.

Network delivery and network capability

The long-term reduction in projected constraint costs in the early 2030s is closely linked to the delivery of planned transmission reinforcements. Changes to project delivery timescales, project scope or network availability could affect future thermal constraint costs, particularly in the period to 2035.

Market conditions

Future constraint costs are also influenced by wider market conditions, including fuel prices and interconnector flows. These factors primarily impact the cost of redispatch actions and may result in higher or lower costs than projected.

Outages and operational conditions

Planned and unplanned outages can significantly reduce transmission capability and increase constraint costs over short periods. Outage programmes continue to evolve as the electricity system changes. TOs require outages to maintain existing assets, connect new customers and to deliver major network reinforcements, while we work with industry

partners to coordinate and optimise the overall plan. The process is inherently complex, as outages cannot be assessed individually and must instead be considered alongside other outages, changing network conditions, generation connections and system security requirements. Future outage programmes should therefore be viewed as evolving plans rather than fixed schedules.

Outages influence the level of transfer capability available on key network boundaries. Analysis to test the sensitivity of the projections to lower transfer capability across key England and Wales boundaries shows that relatively small changes in transfer capability assumptions can lead to material changes in projected thermal constraint costs. The analysis indicates that a 10% variation in transfer capability assumptions can alter annual projected costs by around 8-20% between 2027 and 2030, highlighting the importance of outage-related assumptions within the modelling. These sensitivities do not reflect the impact of near-real-time operational measures that can help maintain network capability[10], such as Dynamic Line Ratings (DLR) and constraints bypass arrangements, and should therefore be interpreted as a conservative view.

Interconnector Flows and Trading Arrangements

Future interconnector flows depend on a range of factors, including cross-border market conditions, the relative cost of generation in GB and neighbouring markets, and future interconnector deployment.

Changes to interconnector trading rules and restrictions on cross-border trading would alter both interconnector flows and balancing costs.

[10] The level of modelling granularity required to capture these savings is not feasible within a long-term projection model. They are therefore assessed separately and on an individual basis.

Work to Address Thermal Constraints

The projections set out how thermal constraint costs could evolve as the electricity system develops. Taken together, they highlight three priorities for action:

1. **Deliver the network capability needed to support a growing electricity system**
2. **Improve long-term outcomes through strategic planning and market reform**
3. **Continue reducing the cost of managing constraints in the near term**

These priorities respond to the three interconnected drivers of thermal constraint costs. Near-term operational and market improvements primarily seek to make better use of available network capacity and to reduce redispatch costs. Network reinforcement increases the capacity available to transport electricity between regions. Over the longer term, strategic planning and market reform will be critical to better coordinating generation, demand and network development, and improving the signals and incentives that shape operational and investment decisions. Because the drivers interact, many initiatives contribute to more than one priority and driver.

This section sets out how we are working alongside government, Ofgem, TOs and industry to minimise constraints.

In the near and medium term, our focus is on supporting timely delivery of critical network infrastructure while limiting constraint volumes and costs in the interim. This includes improving outage coordination, making better use of the existing network, strengthening forecasting and operational decision-making, and widening access to balancing resources.

Over the longer term, sustained reductions in constraint costs will require better alignment of generation, demand and network development, alongside changes to market and dispatch arrangements. These changes have the potential to address the underlying causes of constraints but will require coordinated action across industry, changes to market arrangements and significant infrastructure investment.

Through its Siting and Investment Levers workstream, initiatives such as the SSEP, CSNP and locational incentive reforms seek to improve how generation, storage, demand and networks develop over time. In parallel, the Balancing and Settlement Reforms and Constraint Management workstreams are considering reforms to system operation and constraint management. We are exploring whether changes to dispatch arrangements could better align market outcomes with the needs of the physical system, reducing the corrective actions required to maintain system security in real time.

The initiatives set out in the remainder of this section are grouped by the driver they most directly affect and their stage of maturity: ‘Ongoing’ initiatives are already being delivered; ‘In progress’ initiatives are being developed or implemented; and ‘Early stage’ initiatives remain at an earlier stage of design, assessment or exploration. Further detail on each initiative and, where available, its expected impact is provided in the supporting table.

Further details of each initiative and, where available, its expected impact can be found here.

Regional supply and demand imbalances require a combination of operational improvements and long-term system development

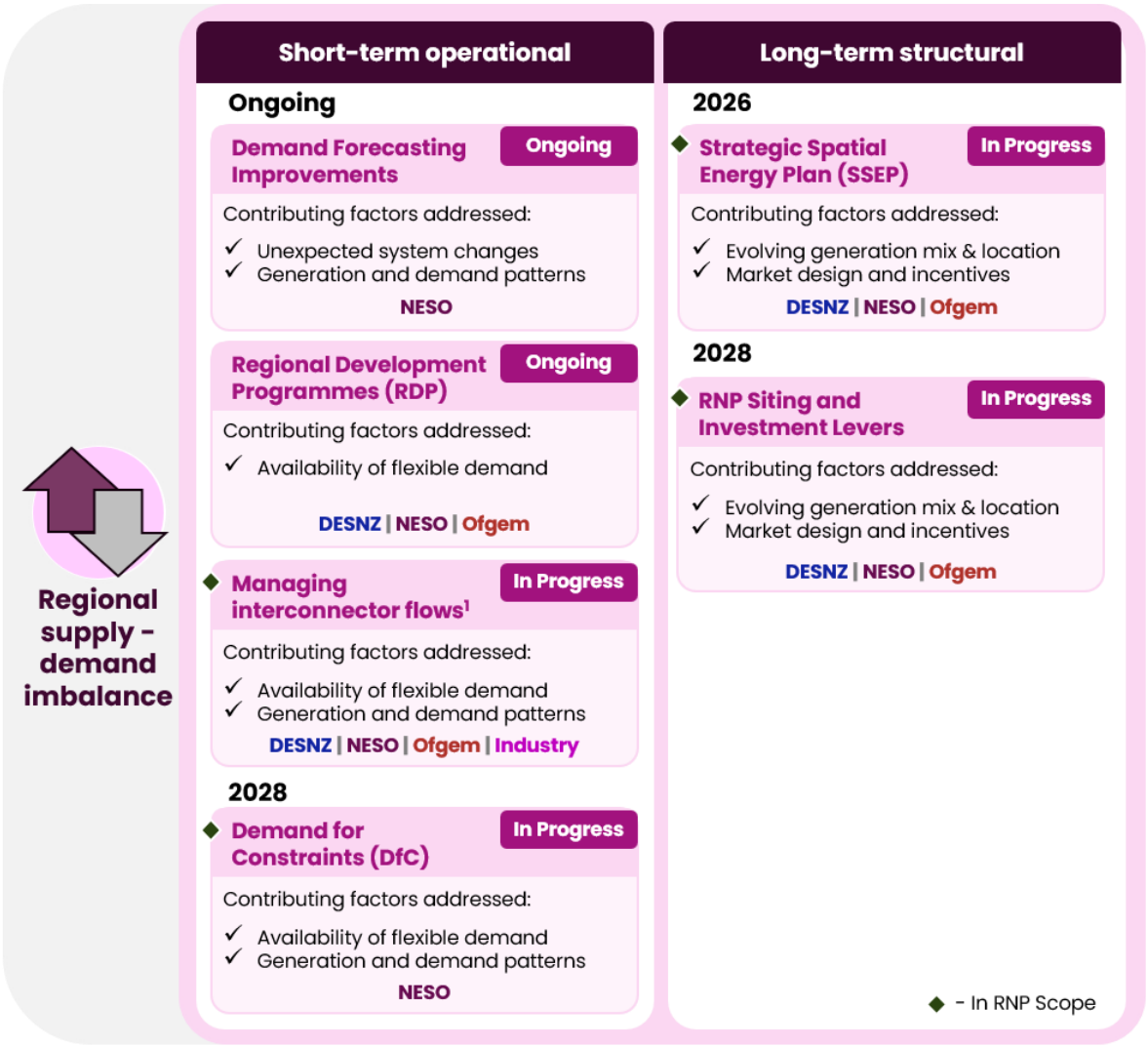
Many drivers of regional supply and demand imbalances, including weather patterns, generation output and market behaviour, sit outside our direct control. Better forecasting, planning and coordination can help reduce their impact.

In the near term, demand forecasting improvements and Demand for Constraints (DfC) help improve operators' ability to anticipate regional supply and demand imbalances and to optimise how constraints are managed within existing market and network arrangements. Over the longer term, strategic initiatives such as the SSEP and reforms to siting and investment levers under RNP seek to strengthen the signals available to market participants when making investment and operational decisions, helping generation, storage and demand develop in locations that make more efficient use of the network.

SSEP and CSNP

The Strategic Spatial Energy Plan (SSEP), expected in 2027, will set out a long-term blueprint for the location, scale and timing of future electricity and hydrogen generation and storage across Great Britain. The Centralised Strategic Network Plan (CSNP) will use outputs from the SSEP to inform a coordinated long-term plan for the electricity and gas transmission networks, and the hydrogen system needed to support that future system. Together, these plans are intended to better align the development of generation, storage and demand with network capacity, helping to reduce regional imbalances and the resulting network constraints over time.

Figure 7 below shows how operational measures and longer-term planning and market reforms can help anticipate regional imbalances, manage their effects and improve the future alignment of generation and demand.



Notes: 1) This includes Net Transfer Capacity restrictions to limit interconnector flows where necessary to maintain system security.

Figure 7: Initiatives addressing regional supply-demand imbalance[11]

Making better use of the existing network while delivering future infrastructure is key to increasing available network capacity

Increasing network capacity requires close coordination between NESO, TOs, Ofgem and government. We plan and operate the system, coordinate outages and identify opportunities to maximise the use of available capacity. TOs maintain and develop the network and deliver reinforcements, while Ofgem establishes the regulatory framework

[11] How to read this diagram: The diagram sets out proposed initiatives spanning operational measures and longer-term changes to the system, alongside indicative delivery dates and the key parties involved. It also shows which of the contributing factors, identified in Figure 3, each initiative seeks to address.

and approves efficient investment. Government provides the wider policy and strategic direction.

Measures to increase the capability and availability of the existing network include:

- **Enhanced Network Provisions[12],** such as auto switching and Dynamic Line Rating (DLR), increase network capability and enable greater power flows. These measures delivered estimated savings of £356m in 2025/26, while expanded DLR deployment is projected to deliver further savings of ~£800m-£1b between 2026 and 2030[13].

- **Constraint Intertrip Services** enable greater power flows across constrained boundaries while maintaining system security. Existing schemes delivered estimated savings of £22m in 2025/26, with further ~£75m-£205m[14] expected through future scheme expansion in the EC5 boundary. The scheme will also be extended to the B2-B5 and B6 boundaries, but as contracts are in early stages of tender, savings forecasts are not published in this report.

- **Network Topology Optimisation and Outage Optimisation**, maximise available network capability through improved network and outage planning. Network Topology Optimisation is forecast to deliver savings of ~£260m-£400m[15] between 2028 and 2033.

Over the longer term, sustained increases in available network capacity depend on network expansion keeping pace with changing system needs. Programmes such as ASTI, the CSNP and System Access Reform (SAR) are intended to improve network planning, coordination and delivery, increasing network capability and reducing future constraint volumes.

Figure 8 below brings together the operational measures that maximise the use of existing infrastructure and the longer-term programmes supporting network expansion.

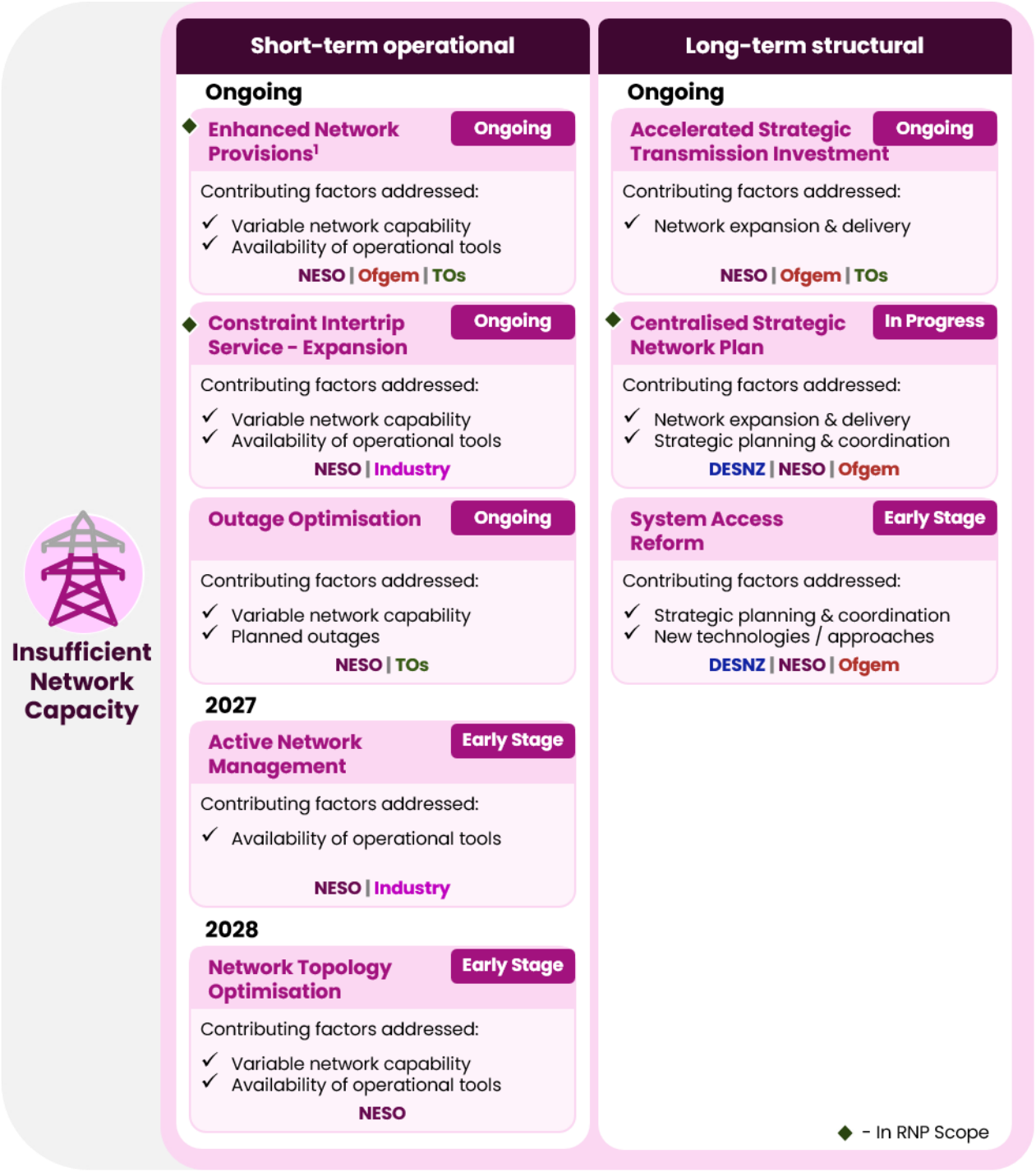
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[12] Enhanced Network Provisions (STCP11-4) include the range of operational and engineering solutions that make better use of the existing network, including dynamic ratings, automated switching and constraint bypass.

[13] Forecast savings from DLR are estimated by comparing modelled constraint costs under baseline network capabilities with scenarios assuming a 3–8% increase in capability on relevant boundaries. The range is informed by observed data, averaged across varying weather conditions, and represents the capability potentially available using day-ahead information and closer to real time. The estimates are indicative and may change as assumptions are refined with TOs.

[14] Forecast savings from Constraint Intertrip Services compare the expected intertrip contract expenditure with the avoided cost of generation curtailment and replacement energy in the Balancing Mechanism. The analysis uses the four FES 2024 pathways and represents the benefit of reducing Balancing Mechanism expenditure.

[15] Forecast savings from Network Topology Optimisation are early-stage estimates, informed by evidence from international applications and existing manual network-optimisation activity. The estimates will be refined through further analysis following completion of pilot work to test the approach against existing processes.



Notes: 1) Enhanced Network Provisions (STCP11-4) include the range of operational and engineering solutions that make better use of the existing network, including dynamic ratings, automated switching and constraint bypass

Figure 8: Initiatives addressing insufficient network capacity[16]

[16] How to read this diagram: The diagram sets out proposed initiatives spanning operational measures and longer-term changes to the system, alongside indicative delivery dates and the key parties involved. It also shows which of the contributing factors identified in Figure 3 each initiative seeks to address.

Increasing access to balancing resources and improving their use can help reduce redispatch costs

Redispatch costs are influenced by wholesale electricity prices and wider market conditions, but can also be affected by the range, price and deployment of the actions available to manage constraints. Near-term initiatives focus on widening participation in balancing markets, increasing competition and improving operational decision making.

The evolution of the Local Constraint Market (LCM) into the Demand Flexibility Service (DFS), is focused on reducing the price of thermal constraint actions by maximising competition and enabling access to new resources such as demand-side flexibility. Other reforms, including the trial removal of Final Consumption Levies (FCL) and NESO trading activities, seek to improve market access and increase competition. The Open Balancing Platform (OBP) improves operational decision-making by helping control room operators identify and deploy more efficient balancing actions.

The initiative to remove subsidies from bid prices (P462) seeks to improve market efficiency by removing the effect of certain subsidies from Balancing Mechanism bid prices. External analysis commissioned through the BSC modification process identified potential net welfare benefits of £1.3bn to £1.8bn[17]. As part of that assessment, sensitivity analysis explored the impact of lower storage deployment in GB. This analysis found that relatively small reductions in storage capacity (1.3-2.2GW) could remove the overall welfare benefit, while substantially larger reductions (9.1-15.1GW) would be required before consumer benefits became negative. This analysis highlights a broader challenge when assessing whole-system reforms: benefits and costs may fall unevenly across market participants. In this case, welfare and consumer outcomes remain positive across a wider range of assumptions than outcomes for some producers, illustrating the importance of considering both system-wide and participant-specific impacts.

[17] Based on CEPA's Impact Assessment of P462 for Elexon (March 2026), available via the P462 modification page. Results are presented for illustrative purposes only, as the assessment is based on a separate modelling framework and assumptions, including FES 2024 and CP30 inputs. The £6.6bn NPV Contract for Difference (CfD) reform scenario and subsequent sensitivities on materially reduced storage and demand flexibility deployment are not included in the range presented here.

Constraints Collaboration Project (CCP)

Since January 2024, we have been working with industry through the CCP to identify practical solutions that can reduce thermal constraint costs in the near term. Several options are currently being progressed:

- **Demand for Constraints:** Incentivises additional flexible demand to increase consumption in constrained areas, reducing generation curtailment and balancing costs.
- **Extended Constraint Intertrip Services:** Several options are being assessed to expand existing intertrip arrangements and increase the volume of power that can flow across constrained boundaries while maintaining system security.
- **Constraints Management Markets (CMM):** Explores options for targeted constraint management markets that could improve access to balancing resources in constrained areas. This includes approaches focused on securing replacement generation ahead of time, as well as options that build on the Local Constraints Markets (LCM) trials and seek to increase the participation of demand-side flexibility through Demand Flexibility Service (DFS).

Note: The Boundary Flow Smoothing project has now concluded. Further information on the outcomes of the project can be found here.

Looking further ahead, we are exploring whether changes to dispatch arrangements could better align market outcomes with the needs of the physical system and reduce the volume of corrective actions required to manage constraints. This includes work through RNP and supporting initiatives such as TIDE and Volta, which are considering how operational tools, market arrangements and control room capabilities may need to evolve as the electricity system becomes more decentralised and complex.

Figure 9 below shows how current and planned measures act across market participation, competition, dispatch and operational decision-making to reduce redispatch costs.

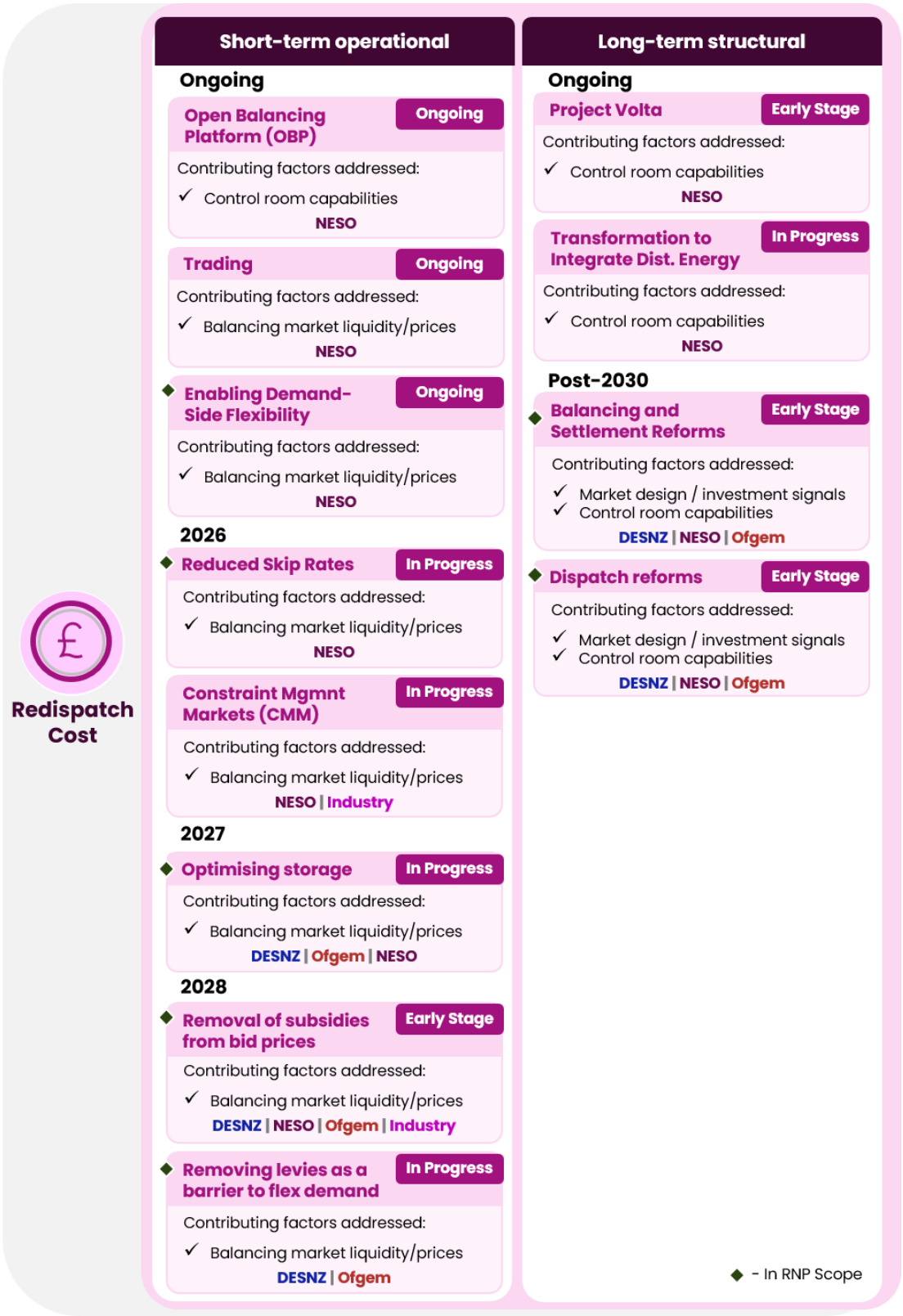


Figure 9: Initiatives addressing redispatch costs[18]

[18] How to read this diagram: The diagram sets out proposed initiatives spanning operational measures and longer-term changes to the system, alongside indicative delivery dates and the key parties involved. It also shows which of the contributing factors identified in Figure 3 each initiative seeks to address.

Glossary



Acronym	Description
ASTI	**Accelerated Strategic Transmission Investment.** A programme to accelerate the delivery of strategic electricity transmission projects required to support the transition to a net zero electricity system.
BSUoS	**Balancing Services Use of System.** Charges used to recover the costs incurred by NESO in balancing and operating the electricity system.
CCP	**Constraints Collaboration Project.** A NESO and industry collaboration established to identify practical measures that can reduce thermal constraint costs.
CfD	**Contract for Difference.** A government support mechanism that provides eligible low-carbon generators with price certainty through a contractual strike price.
CMIS	**Constraint Management Intertrip Service.** A service that allows greater power flows across constrained network boundaries by rapidly disconnecting contracted generation when specified network conditions occur.
CMM	**Constraint Management Markets.** Proposed targeted markets intended to increase access to resources that can help manage constraints.
CSNP	**Centralised Strategic Network Plan.** NESO's coordinated plan for the development of the electricity transmission network required to support the future energy system.
DESNZ	**Department for Energy Security and Net Zero.** The UK government department responsible for energy security and net zero policy.
DfC	**Demand for Constraints.** An initiative that seeks to incentivise flexible demand to increase electricity consumption in constrained areas, reducing the need to curtail generation.
DFS	**Demand Flexibility Service.** A service that enables consumers and other demand-side resources to provide flexibility by changing when they use electricity.
DLR	**Dynamic Line Rating.** The use of real-time or forecast conditions to better determine the transfer capability of overhead transmission lines, allowing the network to be used more efficiently when conditions permit.
FCL	**Final Consumption Levies.** Policy-related charges applied to electricity consumed by end users.
FES	**Future Energy Scenarios.** NESO's pathways exploring how the future energy system could develop under different assumptions. The pathways explore potential energy market evolution and are not forecasts.

Acronym	Description
GB	**Great Britain.** England, Scotland and Wales.
LCM	**Local Constraint Market.** A market arrangement designed to procure flexibility from resources located in areas affected by network constraints.
NGET	**National Grid Electricity Transmission.** Owns and maintains the transmission network in England and Wales.
NTC	**Net Transfer Capacity.** The maximum level of electricity that can be transferred across an interconnector while meeting applicable security standards.
OBP	**Open Balancing Platform.** NESO's platform for identifying and dispatching balancing actions more efficiently.
P462	**Balancing and Settlement Code Modification P462.** A proposal to remove the effect of certain subsidies from Balancing Mechanism bid prices.
RDP	**Regional Development Programme.** A collaborative programme used to develop and test coordinated solutions to regional electricity-system challenges.
RNP	**Reformed National Pricing.** A programme of reforms covering siting and investment signals, balancing and dispatch arrangements, and constraint management.
SAR	**System Access Reform.** Work to reform how access to the electricity transmission system is planned and managed, supporting more coordinated and efficient network delivery.
SPT	**Scottish Power Transmission.** Owns the transmission network in southern Scotland.
SSEN	**Scottish & Southern Electricity Networks Transmission.** Owns the transmission network in northern Scotland and the Scottish islands transmission assets.
SSEP	**Strategic Spatial Energy Plan.** A long-term spatial plan setting out the location, scale and timing of future electricity and hydrogen infrastructure across Great Britain.
STCP 11-4	**System Operator–Transmission Owner Code Procedure 11-4.** The procedure covering enhanced transmission capability arrangements used to make better use of the existing network.
tCSNP	**First Transitional Centralised Strategic Network Plan.** The transitional network-planning process preceding the first CSNP. Published as *Beyond*

Acronym	Description
	2030, it identifies recommended electricity transmission reinforcements required beyond 2030.
tCSNP2	**Second Transitional Centralised Strategic Network Plan.** Published as *Beyond 2030 Update*, it identifies updated recommended electricity transmission reinforcements required beyond 2030.
TIDE	**Transformation to Integrate Distributed Energy.** Initiative to improve visibility and coordination of distributed energy resources across transmission and distribution system operation.
TO	**Transmission Owner.** A company responsible for owning, maintaining and developing parts of Great Britain's high-voltage electricity transmission network.
Volta	**The Volta Programme.** A programme or initiative considering the future development of operational tools and control-room capabilities.

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