STONEHAVEN

RETHINKING ENERGY NETWORK REGULATION

KICKSTARTING A DEBATE ON HOW WE DELIVER
THE ENERGY INFRASTRUCTURE OF THE FUTURE

FOREWORD

The delivery of net zero is of course one of the biggest challenges the UK will ever face, with wholesale change required across vast parts of the British economy. A key question is whether we have the right regulatory and broader institutional framework to deliver this.

The establishment of the National Energy System Operator (NESO) is a significant and positive step forward in the energy sector and the biggest institutional change since the privatization of the energy sector and the contemporaneous establishment of independent economic regulation.

There is a clear role for NESO. Its interface with Ofgem and the nature of how Ofgem regulates the energy sector will, however, need to be carefully worked through. At a national level for the expansion of the national electricity transmission system this looks relatively straightforward. In simple terms NESO will produce national plans and Ofgem's role will be to ensure that the various players such as National Grid are provided with the certainty and incentives to deliver the necessary investment efficiently. There will of course be a role for Government too in signing off and approving (or not) any plans.

At a more local level the planning of energy systems takes on a more complex dimension requiring much more consideration of trade offs between different energy vectors. For example, the size of the electricity distribution network will of course be heavily influenced by what load it needs to take for domestic heating. A gas network repurposed for hydrogen to take a good proportion of heat load, versus a situation where heat was provided by heat networks and electrification, would yield very different answers. The electricity distribution system after all was never designed to carry the energy load provided by the gas network (roughly three times on average and six time on a peak day). Also, as technology changes the chosen option might well change and changing consumer attitudes will also have a significant bearing on the acceptability or not of evolving technologies. Building in flexibility will therefore also be important.

The situation in the UK is further complicated by the fact that unlike many European countries we have very separate ownership of gas and electricity infrastructure – which also have quite different geographical footprints.

All of this illustrates the complexity of planning and regulation at a more local level. That is why we sought to commission this piece of work to start to shed light on this important issue. We need long term certainty for investment to keep costs and bills down for consumers, but at the same time we will need to be agile and fleet of foot to respond to how different technological solutions might change what might be the right decarbonisation pathway to pursue. And the 'right' pathway may very well vary from one region to another across the UK according to housing stock, the availability of hydrogen, the capacity of the electricity network etc. And of course, we need to take consumers and local communities with us on the journey to net zero. This is a very difficult nut to crack!

I hope this report helps to stimulate the debate around this and other related issues to help ensure our regulatory institutions evolve in the way in which they operate to enable the effective and efficient delivery of net zero.

AJ Ball

Dr Tony Ballance

CHIEF STRATEGY & REGULATION OFFICER

FOREWORD

Stonehaven's report addresses the challenge for energy network regulation: How to transform the sector to achieve net zero while taking consumers and local communities with us? Revised regulatory arrangements seem to be in process for transmission but not for distribution networks.

The report documents the nature and extent of the problem. It explains the problems posed by uncertainty – as to technologies, costs, and customer preferences and responses. There are also trade-offs: Who gets what? Who gains and who pays? Whose choices are expanded and whose are restricted? If not well handled, this can lead to political disputes and delays.

So there is a strong case for change – but what alternative regulatory approach would solve these twin challenges of radical uncertainty and lack of political consent? Various options for democratic central planning are evaluated and dismissed as either ineffective or too radical. Instead, Stonehaven proposes an innovative Pathway Planning approach, enabling investment in defined stages based on branching pathways and 'trigger data'.

This obviously raises questions – for example, in the presence of extensive uncertainty and political disagreement, is it any easier to define the pathways and the triggers than it is to choose an optimal solution? So here I would like to explore and endorse Stonehaven's suggestion for developing the role of the existing challenge panels – "involving representatives of consumers, customers for network connections like industry, academics and NGOs" (p 27) – to provide additional scrutiny of any proposed branching pathways and investment triggers.

Frequent public controversy about regulatory price controls in the 1990s led me to explore whether other countries did it better. I discovered that in parts of the US, and elsewhere, concerned customer groups occasionally negotiated with regulated companies and proposed an agreed settlement to the regulatory body, which it was grateful to accept. I suggested that Ofgem and Ofwat encourage such an approach. The challenge groups referred to have been one very positive outcome, enabling business plans that are more soundly based and generally acceptable.

But Ofgem and Ofwat have reserved to themselves the actual setting of the price controls. And criticisms and disputes have continued there, for example with controversial suggestions that regulators "aim off" in projecting costs and setting price controls.

So my suggestion is that customer and challenge groups be encouraged to negotiate with the regulated companies on the actual price controls as well as on the underlying business plans. Of course, not all these negotiations would necessarily be successful, in which case Ofgem would need to step in. Ofgem would also need to be satisfied that any proposed price control was consistent with its statutory duties. But I would hope, and expect, there would be three main beneficial outcomes of the process.

1) The participating parties would come to a better understanding of each other's concerns, and would explore different ways of accommodating them, rather than abandoning the decision to Ofgem, with its necessarily uncertain outcome.

2) The parties would explore, adopt and develop different and more innovative approaches than it would be possible for Ofgem to do, and so companies and customers in each area, and Ofgem, would learn faster from this quasi-rivalrous discovery process as to what works well and what doesn't.

FOREWORD

3) The parties would gradually develop mutual trust, conducive for example to adjustments within a price control period such as conceding that a successful cost reduction programme might mean that not all of an earlier-agreed price increase needs to taken, but by the same token an unexpectedly costly investment programme might merit a higher allowed revenue than previously agreed.

This in turn would lay the basis for these parties to consider the case for new investments on an ongoing basis. That is, rather than having to agree an investment programme once every five years or so, or having to specify in advance elaborate branching pathways and investment triggers, they could assess investment proposals as and when the time seemed ripe to do so. All this would be in the context of net zero legislation and policy, but it would focus on trying to find a mutually acceptable way forward. And it would be more like a competitive customer-focused market process than heavy-handed regulation.

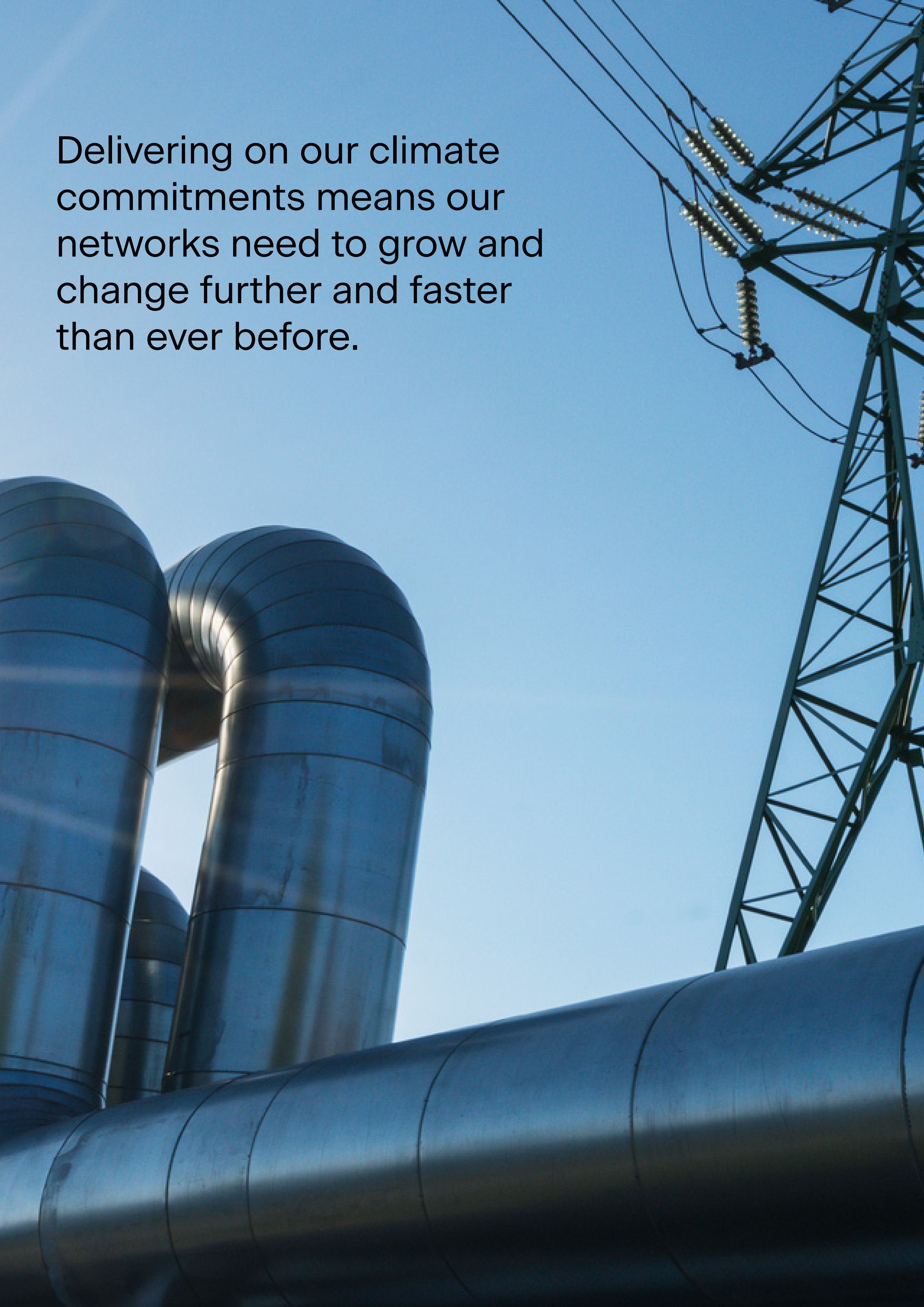
Others will no doubt have their own suggestions, which all need exploration and evaluation in the context of the net zero journey. Stonehaven's thoughtful report thus makes an important contribution to an important regulatory debate, and we should now build upon it.

Stephen Littlechild

Stephen Littlechild

Contents

Delivering on our climate commitments means our networks need to grow and change further and faster than ever before.



01 EXECUTIVE SUMMARY

The UK's energy networks are amongst the oldest in the world. We built our power transmission network in the 1920s, linking up dozens of individual regional and town networks. Our gas networks are older still, dating back to the discovery of coal gas and its use for lighting. Some of the earliest gas networks were made using leftover muskets from the Napoleonic wars.

Over the decades and centuries our networks have evolved and grown. Very nearly 100% of the properties in Great Britain can access electricity, and 80% of households source their heat from gas travelling through pipes that stretch out across the nation. But delivering on our climate commitments means our networks need to grow and change further and faster than ever before. We need to build networks for entirely new fuels such as low carbon hydrogen. We need extensive new transmission connections to link up the wind generation being built at the edges of our existing network. We need to reinforce the cabling in our towns and cities to accommodate electric transport and heat.

While there are disputes about precisely what technologies will go where, the direction towards a low carbon energy system is not in doubt. Therefore, this paper is about how we get there rather than what we do. The method through which we manage both the development of our networks and how they're paid for has also gently evolved since privatisation, and now requires much more radical change. This process has already begun, as the Government spins off the existing strategic system operation functions into a new independent National Energy System Operator. The NESO should be capable of the kind of strategic planning of our large-scale networks needed to drive investment.

But the same is not true at the distribution level, in the lower voltage and lower pressure networks. We do not know what technologies consumers will prefer, but we can anticipate how they will respond to politicians and regulators attempting to choose on their behalf. In Germany in September 2023 the opposition against a proposed ban on boiler-only heating led to politicians being forced to severely water down their plans.[1]

Without the kind of certainty possibly at transmission level, planning local networks – and thus being able to anticipate their costs in a manner necessary for our current regulatory framework to function – becomes extraordinarily challenging. Maintaining the existing framework means finding new ways of developing local political accountability for network plans; without this, plans on the basis of national policy will always be subject to significant risk.

But there is another option, and it rests on accepting that the level of uncertainty facing our networks is so extreme that attempts to anticipate costs in advance are highly unlikely to lead to the outcomes we want.

Our current structure attempts to manage this uncertainty through building re-opening procedures into our price controls, cumbersome bureaucratic devices that delay investment and most importantly delay the upgrades and transformations our networks are likely to require.

This is not an approach suitable for delivering decarbonisation at pace. The regulator Ofgem has ostensibly already recognised this through the Accelerated Strategic Transmission Investment project, which has made decisions about major projects outside of the existing price control process. But this decision was only taken because the regulator was effectively pressured into taking this one-off action when it became manifest that its existing procedures were too slow.

We cannot rely on a similar process working for gas and electricity distribution investment, where the need for upgrades will be dispersed around the country and where a slow pace of delivery will only become apparent with a rising tide of anger from consumers who find they are unable to upgrade to local carbon heating or switch to an electric vehicle.

Instead, we advocate an approach known as Pathway Planning. Rather than having to go back to the regulator for approval for every street-level upgrade, networks should be empowered to invest once certain triggers are reached or evidence becomes available. Pathway Planning would allow evidence to be collated through greater experimentation to discover, for example, the costs of hydrogen or heat network deployment. Pathway Planning would allow investments in defined stages based on 'trigger data' such as the number of electric vehicle chargers or the number of heat pumps installed on a street.

This enables us to make investment explicitly dependent on where and when consumers are buying low carbon devices rather than a central direction and helps reduce the risk that a central planner will get it wrong. The intent would be to ensure that our network is adapted to the needs and preferences of the public, rather than the other way round.

But implementing Pathway Planning through our gas and electricity distribution regulatory processes is a major change in the way decisions are made. A major change for the regulator whose philosophy is based on stable, certain, gradual change and a zero-risk approach to capital investment decisions. A major change for the companies who design networks with maximum contingency with a pre-determined end-state in mind.

Without this change, there is a risk that a combination of politics and information asymmetry delays and increases the cost of our low carbon transition. This is a bad outcome for the regulator, for the companies wanting to invest and for society.

02 A BRIEF HISTORY OF NETWORKS

Role of energy networks

Energy networks transport gas and electricity from supply to consumers. The gas network takes supply from domestic North Sea production; from gas interconnectors between the UK and its neighbours; and from Liquified Natural Gas (LNG) terminals. The transmission network serves some large industrial users such as power stations and heavy industry as well as supplying the regional distribution networks. These distribution networks then supply gas to homes and businesses across the country.

The electricity network has traditionally worked in a similar fashion: large power stations, located close to demand centres, provided power to consumers via the transmission network and then the distribution network. New forms of energy like wind and solar mean the transmission network has to connect remote areas with good renewable resource such as the North Sea. An increasing amount of generation is hidden from the transmission network: solar power connected to the distribution network is making the previously centralised, linear energy system much more complicated.

A very different problem faces the gas network. Net Zero requires a significant shift in our energy supplies away from fossil fuels. Whilst abated gas is expected to play a role in the future energy system, there is significant uncertainty over how much will be needed and where. Future needs are subject to exogenous uncertainties such as economic growth and product efficiency, as well as strategic decisions by Government on how to decarbonise electricity, transport, heat, and industry. Figure 1 illustrates the uncertainty for gas and hydrogen demand.

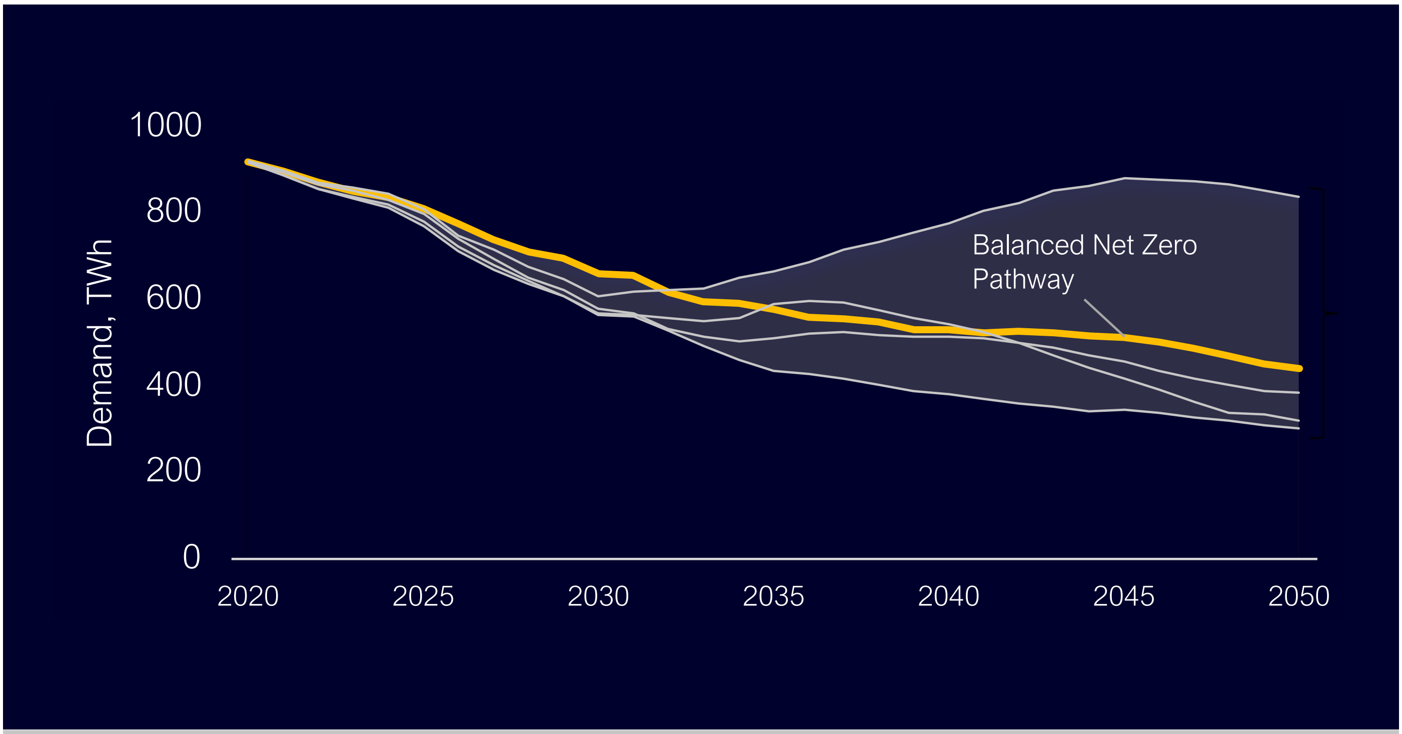
This creates significant uncertainty for gas networks. At one extreme, we see a near-full conversion of the gas grid to hydrogen, with distribution networks continuing to provide fuel to heat homes. At the other extreme, hydrogen is of limited use in shipping and industry (including electricity supply). This latter scenario could mean either pockets of co-located hydrogen production and industrial use, or more centralised production with a converted transmission network supplying industrial users.

Compared to gas, there is much greater clarity around the role of electricity in a net zero economy. Demand is expected to grow as transport and other end uses are electrified. The Climate Change Committee's (CCC's) CB6 scenarios project demand to increase by between 77% to 119% between 2020 and 2050, with their Balanced Pathway seeing an increase of 98% (figure 2).

There are significant regional and technological differences that cast uncertainty on network investment plans, for example: the split of distributed versus transmission connected generation; the extent to which industry electrifies; and the role of electric vehicles (EVs) and other flexible demand in reducing peak load. However, there is a clear trajectory that the networks will need to deliver more electricity to consumers.

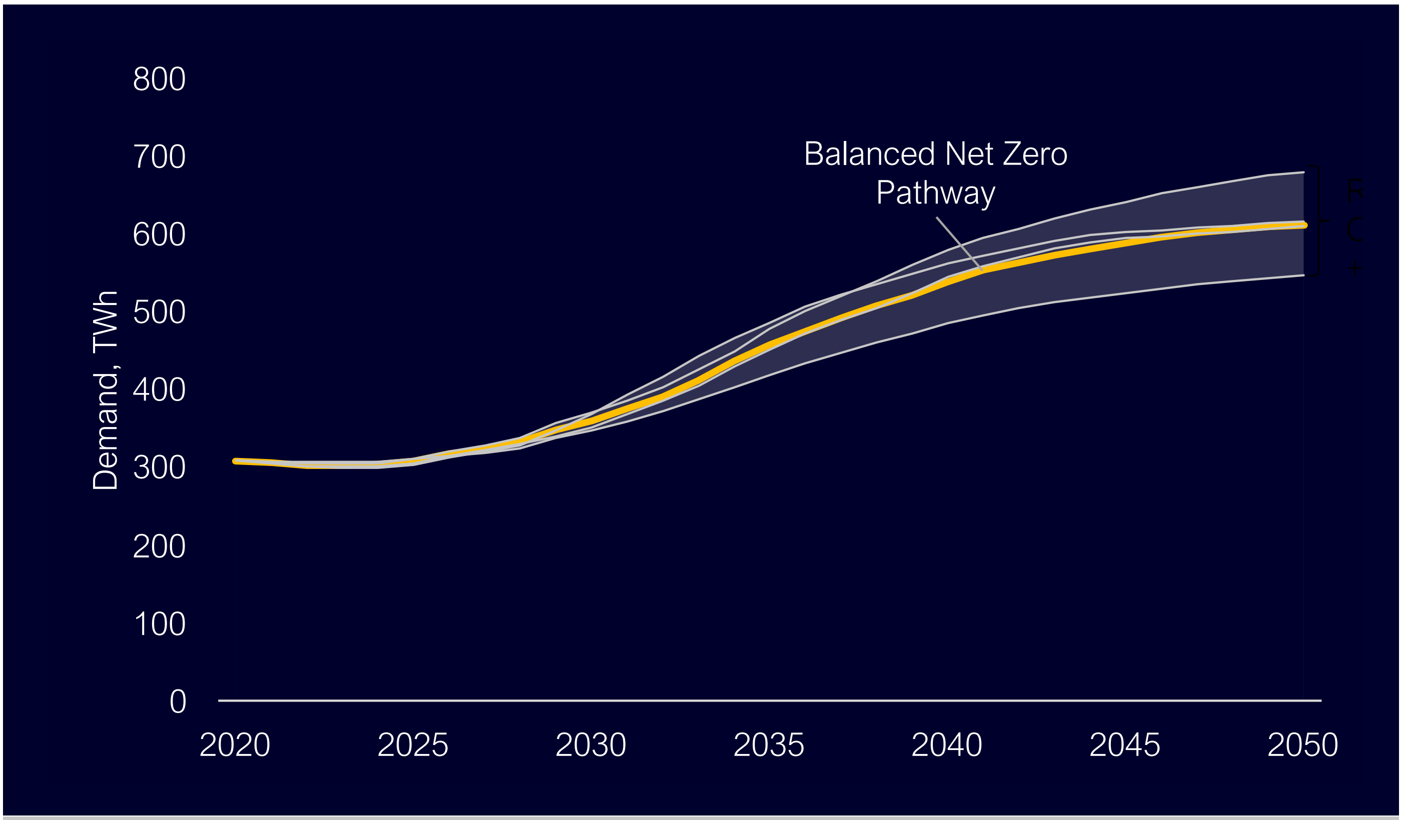
The network will need to cope with this growth in demand, as well as growth in distributed generation. Technological developments mean novel, innovative solutions are now available to address capacity constraints, and a regulatory regime for networks must enable these alternatives to network reinforcement to minimise costs for consumers.

Figure 1: Scenarios for Total Gas Demand (Natural Gas + Hydrogen)



Source: CCC (2020) Sixth Carbon Budget

Figure 2: Projected electricity demand, 2020 to 2050



Source: CCC (2020) Sixth Carbon Budget

Key players and institutions in energy networks

To consider how to tackle the challenges facing networks we must first understand how they are owned and operated. Energy is devolved in Northern Ireland, meaning the institutions discussed apply only to Great Britain. National Gas owns the GB gas transmission network. National Grid owns the electricity transmission network for England and Wales, whilst Scottish Hydro-Electric Transmission and Scottish Power Transmission own the networks for Northern and Southern Scotland respectively (figure 3). Six companies own and operate the electricity distribution network, whilst four cover gas (figure 4).

Each of the network operators (NOs) represent a natural monopoly: they face little competition in transporting energy across their regions. Ofgem regulates their prices and behaviour to mimic the incentives competition would provide to deliver customer value.

Figure 3: Great Britain's Electricity Transmission Network

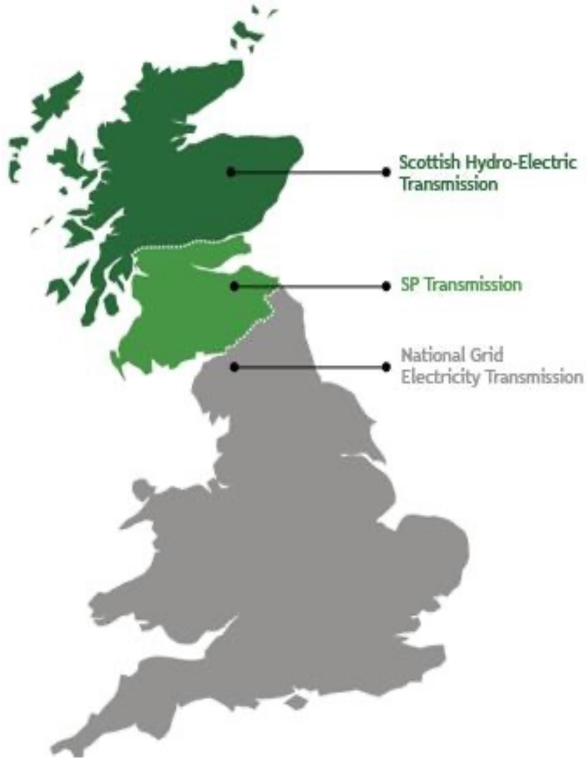
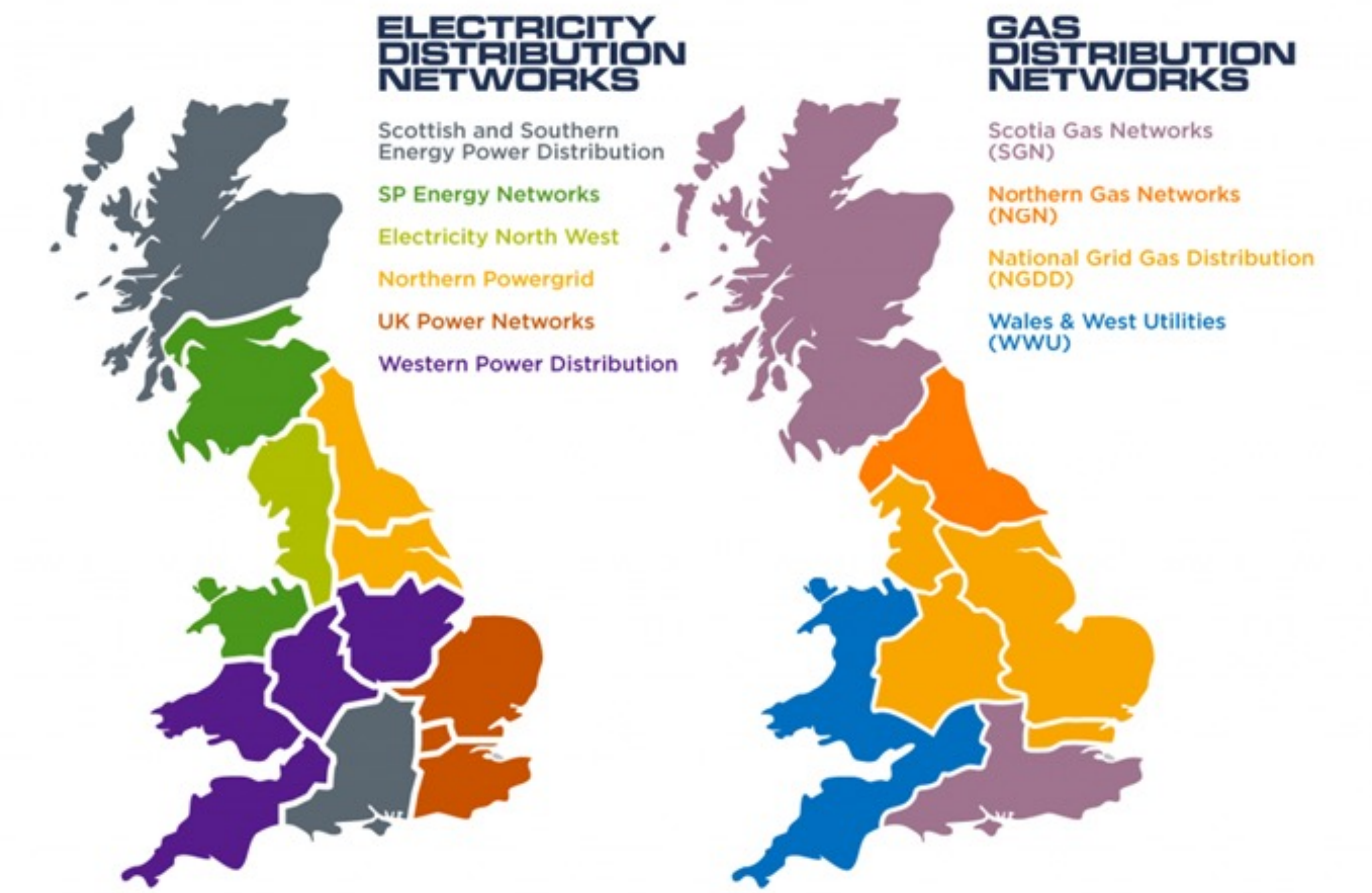


Figure 4: Great Britain's Electricity Transmission Network



History of energy network regulation

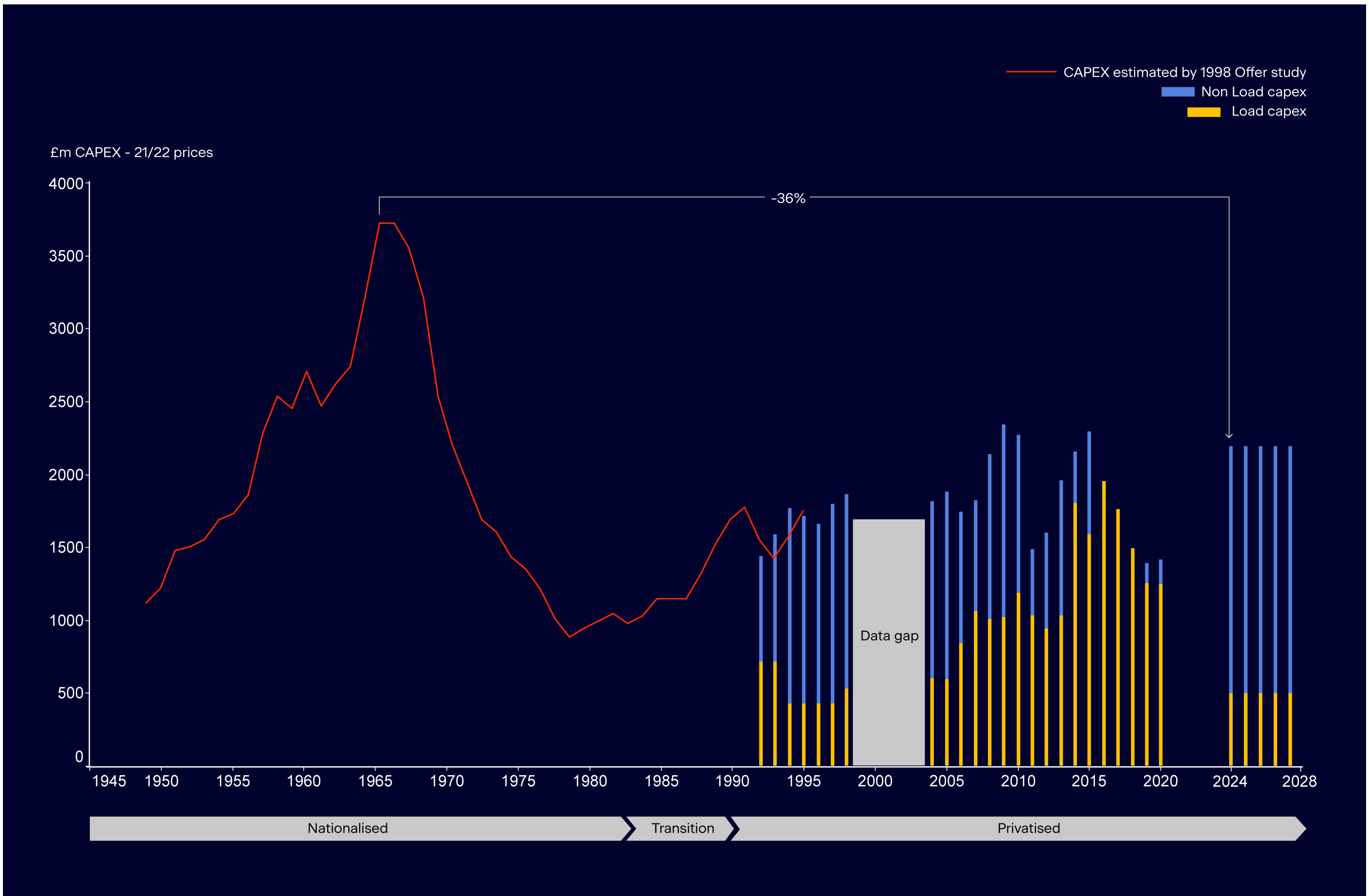
The regulatory regime for Great Britain's energy networks has its roots outside energy in the early 1980s. The Conservative government planned to privatise some of the major nationalised industries, starting with British Telecommunications (BT). This newly privatised company would be a monopoly, exposing consumers to high prices and poor service. It was proposed that BT's prices should be regulated until competition emerged.[2]

'Price regulation' in this sense means that BT would be compelled to only charge a specified amount for its services; this could be in the form of an overall amount or specific tariffs for particular customers. Regardless of the format, the amount recovered by BT would need to be enough to cover the costs of operating and maintaining the network and extending it where needed. Any form of regulation would need to enable this while providing incentives to cut cost normally provided by competition in non-monopoly sectors.

The debate was primarily between a US-style rate of return regulation, an output-related profits levy, or capping prices based on Retail Price Inflation minus an efficiency saving target (RPI-X). Rate of return was seen as overly bureaucratic given it involved significant interrogation of cost data by the regulator in order to set a price. Furthermore, it provided no incentive to cut costs. The output-related profits levy was also rejected.[3] Capping price increases at RPI-X, meanwhile, was seen to have less of a regulatory burden whilst still incentivising efficiency. This regime was subsequently applied to the water, gas and electricity network sectors when each were privatised.[4]

The purpose of this regime was largely about delivering productive efficiency; minimising the costs of existing assets that grew slowly if at all. New investments would need to be within the envelope of an incremental addition to bills. This was facilitated by relatively low levels of investment in some network types (Figure 5) with most capital expenditure ('Non Load Capex') being on replacement of existing assets rather than the expansion of the network.

Figure 5: Electricity Distribution Network Capital expenditure, reproduced with kind permission of Arthur Downing



Sources: (1) Review of Public Electricity Suppliers, 1998-2000, Distribution Price control review, Consultation paper. May 1999.: (2) Electricity Distribution Company Performance 20210-2015, December 2015. Plus supporting data tables: (3) Electricity Distribution Cost review, 2004/5 through to 2009/10: (4) Supporting data files to regulatory financial performance annex to RIIO-1 Annual Reports, 2020-21.

Defining X became a considerable intellectual exercise despite what should have been a relatively simple task of price regulating a relatively unchanging network. Alongside information about operational expenditure, the regulator sought to understand how much investment – in the form of pipes, wires, financing costs and labour – should actually cost and therefore how much of a contribution new investment should make to the value of X.

Given the long life of much of this infrastructure and the need to hold costs down, it was seen as appropriate to amortise new investments over extraordinarily long time periods, up to eighty years in some cases. Network companies as profit-seeking entities would need to make an explicit return on these investments, and so these bundles of amortising infrastructure projects became known as their Regulated Asset Base (RAB). In some networks, including energy, historic network costs were bundled into the RABs of new network companies.

Getting costs right became a permanent struggle for regulators, who would always be at a permanent disadvantage to the companies they regulated who possessed first-hand cost information. Efforts to manage this information asymmetry led to ever more complex regulatory structures, losing the simplicity of RPI-X along the way. But following the passage of the Climate Change Act in 2008, new structures would be needed to handle the very large volumes of investment in energy networks tackling climate change would require.

In 2009, Ofgem launched RPI-X@20 to consider future regulatory arrangements in this new context.[5] At the same time it undertook Project Discovery, a piece of work intended to explore how the energy system would change over the coming decades and set out reforms that might be needed to deliver decarbonisation.[6] Project Discovery forecast additional investment in the system of between £100-200bn by 2020 (2009 prices), of which £20-30bn related to energy networks.[7]

The output of RPI-X@20 was the RIIO regime (setting Revenue using Incentives to deliver Innovation and Outputs) in 2010. RIIO was intended as an upgrade or evolution of RPI-X that constituted a system of regulation better able to manage networks during the transition to a low carbon system; one that better enabled innovation, understanding of consumers, handled uncertainty and ensuring the right capital poured into the right projects.

RIIO set an ex-ante price control based on NOs' outputs; greater opportunities for third parties to deliver network needs; and innovation incentives.[8] RIIO-1 ran from 2013 to 2021 (RIIO-ED1, covering electricity distribution networks, ran from 2015 to 2023). RIIO-2 runs from 2021 to 2026 (RIIO-ED2 runs from 2023 to 2028).

The results of this framework for investment in electricity distribution networks are shown above in Figure 5, which shows the transition period from a nationalised industry to private ownership, investments made under RPI-X and RIIO, and allowed investment over the next price control period. We highlight this here because the jump from current levels of capital investment to that allowed in the future is stark and is fundamental to our argument. The original RIIO ED1 price control had higher capital investment allowances than were actually needed, as Ofgem assumed far higher deployment of low carbon technologies than was actually the case. Some networks chose not to spend this allowance; others did so regardless. The total load-related capital investment underspend by the end of RIIO ED1 was over £2bn.

This illustrates the challenges facing a regulatory model that relies on modelling the future. We will now turn to how this model is intended to function for the purposes of driving investment.

03 CURRENT CAPITAL ALLOCATION FRAMEWORK

Regulated Revenue

The RIIO process begins with Ofgem publishing a strategy document, setting out the framework NOs should use to develop their business plans. Business plans set out how NOs intend to deliver on the outputs specified by the framework, including the investments and expenditure necessary to deliver them. Outputs include 'baseline' outputs around network energy served and timely connection offers as well as additional incentives around cyber resilience and environmental action plans.

The level of scrutiny applied to these business plans is very high. Delivering these outputs has a cost; Ofgem seeks to understand these costs through the detail of the plans themselves, benchmarking NO costs against each other and through externally commissioned research on costs. This is explicitly an attempt to tackle the information asymmetry problem set out above.

Ofgem also needs to take a view as to how these costs will evolve over the course of the price control in order to ensure that NOs have incentives to reduce their costs while not making outsize returns. A key component of this is estimating how demand will grow and therefore what load-related expenditure will be incurred. During RIIO ED-1 the EDNOs spent 27% less than expected on this item, contributing to an overall lower than expected spend of 4%.[9] This illustrates the challenge Ofgem faces in regulating in the face of not just cost uncertainty, but demand uncertainty too.

Ofgem's response to this miscalculation has been to double down on its scrutiny of networks' investment plans. It evaluated over 600 Engineering Justification Papers as part of the development of RIIO ED2 alone, delving as far as possible into the very detailed levels of planning undertaken by networks for their investments. This represents a considerable commitment of officials' time as well as spending on technical advice. The structures that underpin this network planning process are to what we will now turn.

Planning Electricity Transmission

The three electricity transmission network operators (TNOs) plan, build, own and operate the electricity transmission network across Great Britain. National Grid Electricity System Operator (NG ESO) publishes an annual Electricity Ten Year Statement (ETYS) to give a view of electricity transmission needs over the next decade. Using this and the longer term Future Electricity Scenarios (FES) work the ESO also undertakes, TNOs propose solutions to the challenges the ETYS identifies. The ESO then recommends which of these solutions should proceed and by when in their Networks Options Assessment (NOA).[10] Ofgem scrutinise the NOA,[11] which in turn provides a framework for the TNOs to justify the investment component of their business plans more easily. The ESO is to shortly evolve into the National Energy System Operator (NESO) following its splitting out from National Grid's corporate structure.

Outside of price reviews, Ofgem provide opportunities for new proposals via re-openers. For projects under these re-openers, Electricity TNOs must comply with the Large Onshore Transmission Investment (LOTI) regime. This requires TNOs to compete the delivery of a project through an auction,[12] though some projects may go ahead without competition to accelerate delivery.[13] Ofgem estimates that new transmission assets under the LOTI regime take 11-13 years to complete.[14]

In order to speed up this lengthy process, Ofgem has allowed some projects to proceed under the Accelerated Strategic Transmission Investment (ASTI) framework.[15] This exempts certain large, strategic onshore transmission projects from competition in order to speed up delivery. Ofgem apply an output delivery incentive whereby projects are rewarded / penalised for early / late delivery.

Ofgem have also recently introduced a new Centralised Strategic Network Plan (CSNP) through which the NESO can plan the electricity transmission network and advise stakeholders on wider energy system, e.g. hydrogen production and location of new generation.[16]

Off the back of this move, Government has committed to deliver a Strategic Spatial Energy Plan (SSEP).[17] This could give strategic energy planning a formal underpinning in planning and consenting regimes. It could translate Government's national targets into specific locations, allowing other documents such as the CSNP to better plan transmission needs between regions.[18]

Planning Gas Transmission

National Gas run the gas transmission network across Great Britain. National Gas publish an annual Gas Ten Year Statement (GTYS), based on FES.[19] The GTYS represents the start of National Gas' planning cycle: it is the basis of their consultation process in the lead-up to submitting business plans to Ofgem for scrutiny.

The NESO is intended to absorb the gas system operator function from National Gas. At this point, the NESO is expected to include natural gas and hydrogen network solutions as part of its CSNP.[20]

Planning Distribution

Planning the distribution networks is more decentralised than the transmission networks. There are many more actors at the distribution level, with no national system operator acting as the ESO does across the three electricity TOs. As indicated in Figure X above, the challenge Distribution Network Operators (DNOs) have historically faced in assessing investment needs has been relatively stable for several decades, but the advent of heat and transport electrification means that this is on course to change.

The problems facing any attempts to centrally plan lower voltage and lower pressure networks are ones of scheduling and scale.

LOCAL PLANS NOW

To efficiently schedule upgrades or vector transitions at the demand level, a planner needs to know when new assets will be connected to the network. For domestic assets like heat pumps and electric vehicles, this means having insight to what consumers will be buying and when. If a planner knows that a sufficient number of electric heating assets will be deployed in a given geographic area to justify investment, they can schedule that investment to upgrade the network alongside. Conversely, if a planner knows that insufficient electric heating assets are going to be deployed in time to meet decarbonisation targets, they can schedule a transition to another vector.

In both cases, scale (number of assets installed) and timing (when those assets are installed) is critical. DNOs currently utilise FES projections, in-house analytics and demographic information to project when and where to reinforce low voltage networks. Figure 6 illustrates the method taken by Scottish Power Energy Networks (SPEN),[21] whose approach to this is representative of DNO processes across the industry.

SPEN and other networks preparing their RIIO-ED2 business plans explicitly targeted the lowest level of heat pump and electric vehicle deployment compatible with a pathway to Net Zero. This was to ensure costs were controlled. In the event that deployment deviates from this pathway Ofgem's uncertainty mechanisms are intended to kick in, and the DNOs have the option of reverting to Ofgem to enable additional investment.

This 'reactive' approach to delivering network infrastructure, while ostensibly intended to hold down costs, runs the risk of requiring precipitate investment if deployment happens faster in particular locations than expected – and over-investment in areas where it does not. It also very clearly cannot handle questions of scale; right-sizing a network for its eventual 2050 end state may require significantly less investment than the incremental upgrades this approach points to. Having to repeatedly dig up roads or swap transformers in and out is not an efficient path to Net Zero.

Figure 6: Illustration of network planning methodology undertaken by SPEN

These problems are not unique to the UK; the distribution network planning approach taken across a number of jurisdictions including Australia is similar. The latter in particular places a premium on non-network solutions, including smarter management of assets or local generation as an alternative to new wires.

But while scheduling and scale are problems for any individual network's attempt to plan, a far more significant concern is co-ordination across vectors. Do electricity and gas networks have the same assumptions about when a particular street will stop using gas? Do local authorities building heat networks know whether there will be sufficient capacity on local networks to power heat generators into the long term? If consumers move towards hybrid heating, what does this mean for the level of gas network and electric network investment in a given area?

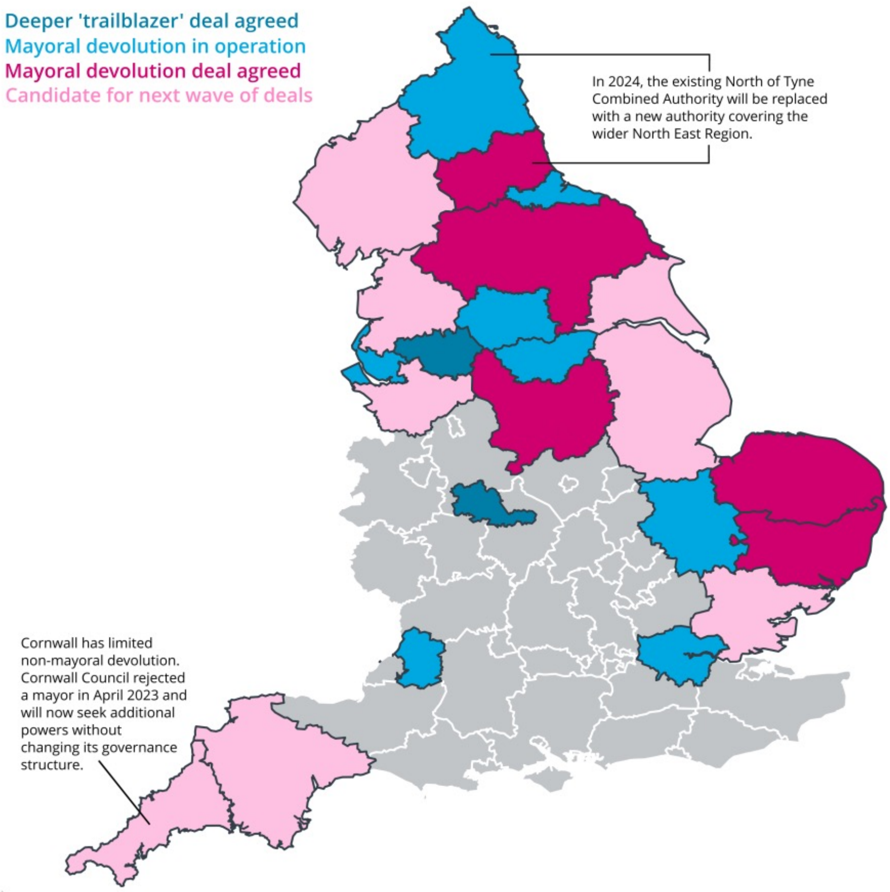
Considerable efforts are underway to try to tackle these problems, including the Government's Heat Network Zoning project[22] and a range of collaborative projects between networks and between networks and local authorities. These are, essentially, attempts to replicate the developing national-level institutional arrangements at a more local level. But there are good reasons to think that they will not succeed – at least, not in the way in which they are intended to.

In the above plans, consumers are effectively treated as a quasi-random exogenous variable making decisions against which networks have to plan. But in the transition to Net Zero, the investments and plans that network companies will actively change the decisions available to consumers. There is no plan to manage the politics of this, and indeed no route through which this could be achieved.

WHO PLANS THE PLANNERS?

Unlike federal systems such as Germany or the US, the UK lacks a uniform mid-tier branch of government with the capacity to manage large infrastructure programmes whilst still accounting for local needs and managing trade-offs between localities within a region (the annex to this paper provides a short explanation of different international arrangements for energy regulation). Below the national government there are three Devolved Administrations in Scotland, Wales and Northern Ireland; 12 planned or operating regional Governments such as Greater London or the East Midlands Combined Authority;[23] and a host of county councils and local authorities with no tier between them and Westminster. Unlike the traditional federal systems, English devolution is asymmetrical and continuously evolving (figure 7), which presents challenges in consistently applying nationwide policy.[24]

Figure 7: Existing and proposed devolution in England, by area (March 2023)



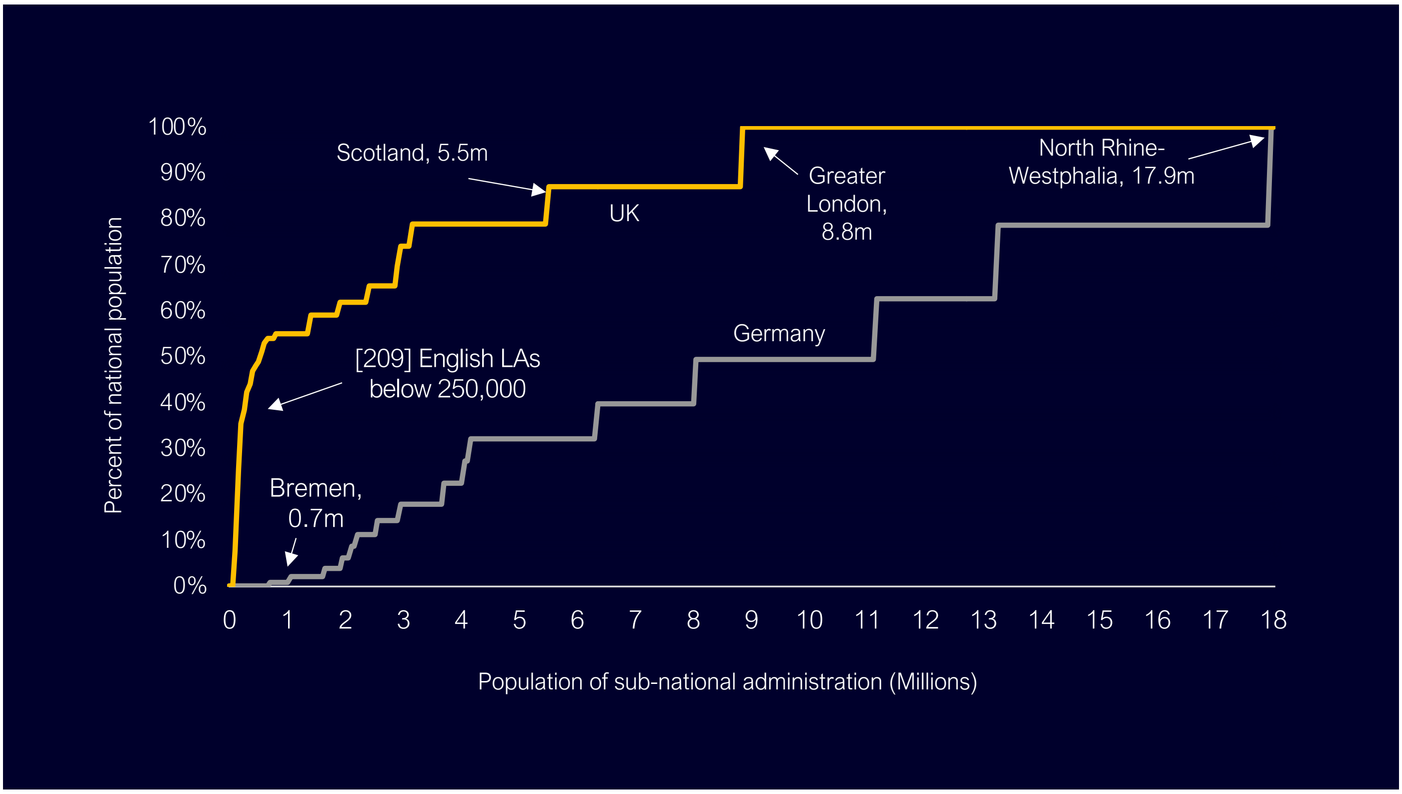
The lack of strong regional administration can be shown through international comparison. Looking at the level of government immediately below Westminster (e.g. the Scottish Government, Greater London Assembly or Buckinghamshire County Council, which we here refer to as 'sub-national layer of administration), over half (55%) of the UK live in sub-national administrations with fewer than 1 million residents (figure 8). The equivalent in federal Germany is 1%, being only the state of Bremen; two thirds of Germans live in states with over 5 million people, a scale only Scotland and Greater London can match.

A larger population implies more tax to fund projects, and a greater pool of talent from which to hire the necessary skills to administer a region. In other words, most of the UK is not covered by a strong sub-national administration. This leaves a significant part of the country without a body with the authority and capacity to deliver significant infrastructural change. National government can deal with transmission-level challenges. But the heterogeneity of distribution networks require more local solutions, and the UK lacks bodies who can find and implement these solutions.

In recognition of this very manifest challenge, Ofgem launched a project in 2022 to consider options for regional governance of energy networks. In 2023 it set out its proposals for a new Regional Energy Strategic Planner (RESP) entity.[25] The purpose of this body is to co-ordinate the spatial planning activities of gas and electricity networks and local authorities, ensuring a common set of assumptions and therefore a common set of outcomes. The body is not intended to be able to overtly override planning decisions made by other parties, merely reveal inconsistencies and potential conflicts of interest.

Despite the name Regional Energy Strategic Planner Ofgem envisages the entity to be in fact a national body with regional branches. Ofgem views its natural home as being within the NESO. This body will be regulated by Ofgem.

Figure 8: Distribution of national populations by size of the highest level of sub-national administration



Unlike federal systems such as Germany or the US, the UK lacks a uniform mid-tier branch of government with the capacity to manage large infrastructure programmes whilst still accounting for local needs.

04 CASE FOR CHANGE

The theory of economic regulation

Economic regulation tries to simulate the impact of competition on monopoly industries. A company that has no competitors – as in the sole licenced providers of an energy network – could in theory set its prices at whatever people would be willing to pay for that service before they would opt for a substitute. The competitors of gas networks are not other gas networks, but rather converting a home's entire heating system to some alternative. Monopoly providers of superior services can therefore extract considerable rents from consumers without offering any additional value.

Reducing these rents can be achieved through simulating competitive pressures. At the simplest level, this can be done by a regulator simply capping how much a monopoly provider can charge for their service. The job of the regulator is then to figure out the right level for that cap; one which encourages needed investment but also puts pressure on the monopoly to innovate and lower its costs in order to increase its returns.

But in doing so the regulator faces a fundamental challenge. To set the right price cap it needs to understand the actual costs facing the companies it regulates. However, it can never have as thorough and granular an understanding of the costs facing the companies as the companies themselves; this is known as information asymmetry.[26] How this is managed is perhaps the key question of economic regulation.

In the earlier section on the history of regulation of networks we discussed two methods of doing so: rate of return regulation and RPI-X. Rate of return is commonly used across the globe as the desired means of regulation, but how that is determined varies.

Italy uses an assessment of the building blocks of cost for networks such as costs of capital, depreciation and maintenance to establish allowed rates of return. Australia uses a version of capital asset pricing modelling – in other words, seeking to identify the returns made by similar assets in competitive markets – to set revenue. The US takes a similar approach, albeit varying by regional system operator.

RPI-X was selected as the basis of the UK's approach to the economic regulation of private monopolies in the 1980s in part on the grounds that it could require less understanding of costs on the part of the regulator. The regulator, if it chose, could simply select an X that represented its willingness to accept costs higher than the prevailing rate of inflation rather than attempt to delve deep into the cost structures of the regulated companies.

In practice the slow mission creep of Ofgem in the intervening decades has meant that the ever-greater level of specification in the RIIO process has become the dominant route for Ofgem to attempt to solve the asymmetry problem. Asymmetry is less of a challenge when the regulator specifies every activity a regulated company can do, signs off every investment decision and approves every new project. But this still relies on Ofgem's staff being capable of outthinking their considerably better paid counterparts in the network companies; it is highly unclear that this is in fact achievable.

Moreover, in order to deliver this framework, Ofgem seeks to manage not only its information asymmetry with the companies it regulates but also the future. Even a five-year price control can see a very different level of demand and a very different technological landscape by its end, especially in the context of decarbonisation. It is this challenge where we think the case for change is most pressing.

Local problems need local solutions

We believe the CSNP/SSEP regime that the Government, the regulator and the System Operator are moving towards is an eminently sensible route for managing the scale of the build-out of large scale infrastructure needed for Net Zero. The problem is clearly defined and there is a strong consensus across the major political parties of the need to build additional connectivity, although any new connections will almost certainly face local opposition.

There are many challenges at the electricity transmission level: projects take too long to build, decisions can fall between the cracks;[27] and there is a lack of strategic thinking. Yet these have been identified and many are being resolved.[28] Crudely speaking, the electricity transmission network is a centralised problem with easily modelled variables. We know electricity demand will rise. We know new generation will be sourced in areas with good renewable resources.

The same is not true closer to home, quite literally. It is considerably harder to model the preferences of tens of millions of consumers on the distribution network than it is to model the tens of actors interacting with the transmission network. This is the nub of the issue. While the ESO can meaningfully claim to have adequate information about the location of large-scale future generation and when it will be developed, the same is not true of demand.

Historically this has not been important as demand has not substantively varied within network planning periods – despite projections under RIIO ED1 indicating otherwise - but this is no longer the case. The CCC's Balanced Net Zero pathway includes 15 million electric vehicles on our roads by 2030 supported by nearly 400,000 public charge points and millions of individual domestic chargers. Fulfilling this pathway would mean that five million homes will have a heat pump of which two million will be on the existing gas network, a number that will triple by 2035.

Under the RIIO framework and Ofgem's high scrutiny regulatory model, decisions around the upgrades needed to support this level of change will need to either be defined at the outset of the price control or through an ongoing series of re-openers. This means Ofgem struggling to analyse potentially thousands of individual engineering projects across the country or necessary grid upgrades being delayed while a control re-opening process is undertaken. The cost base of the price control will also be subject to even higher uncertainty. All the cables, transformers pipes and switchgear needed for this transition will be in demand in significantly higher volumes than before, with the IEA predicting global investment in electricity networks alone tripling by 2040.[29] A benchmarking exercise at the start of a five-year period will rapidly become out of date. The uncertainties facing the regulator are significant; we sketch them out below.

What needs to be known to plan investment in a distribution network?

The current model effectively only assumes one future against which allowed investments in networks are set at the start of a price control. Uncertainty mechanisms exist within the control in the full knowledge that this assumption is almost certainly incorrect. Area of uncertainty include:

TOTAL GAS & ELECTRICITY DEMAND

This is a function of economic and population growth as well as technological change and the delivery of low carbon technologies. The pace of the rollout of new devices is partially clarified by the frameworks Government is using to deploy heat pumps and EVs, which mandate manufacturers to sell a certain number every year. Manufacturers always have the opportunity to buy out of their obligation if deployment becomes too expensive, meaning that the headline figure in these policies will not necessarily be delivered. Gas demand is subject to considerable uncertainty while the role of blue hydrogen remains in flux; the latter will require its own network investments even if existing infrastructure is not utilised.

Currently this uncertainty is managed through modelling exercises, including the ESO's Future Energy Scenarios work. Historically technology deployment has tracked the less ambitious scenario presented each year but this pattern remaining consistent would mean that heat pump deployment would track its 2023 'Falling Short' scenario. This scenario sees Government miss its heat pump deployment targets; whether this is politically acceptable is open for debate.

THE LOCATION OF CHANGES IN DEMAND

This is a function of the spatial distribution of economic and population growth as well as what kinds of consumers take up low carbon technologies first; we saw in the previous section how DNOs attempt to anticipate these. Early adopters of heat pumps and electric vehicles have historically been better off, and current models used for planning assume this trend will continue, modulated by property type. But this is not a given, and some properties and locations may be better suited to hybrid devices or advanced storage heaters. Significant assumptions about load shifting to minimise network constraints are used in many forward models, but the power market is only gradually being designed to deliver these and consumer appetite for these services has not been high even amongst early adopters.

As the decade rolls on, the most important determinant of this uncertainty will be what energy vector is used to deliver heat – electricity, gas, biomethane, hydrogen, or hot water in a heat network. The strategic role of hydrogen in domestic heating remains subject to decision by DESNZ in 2026 once a series of tests have provided data on e.g. safety. Electrification is not a homogenous category. Some property types (e.g. small flats) may be more efficiently decarbonised through advanced storage heaters or air to air heat pumps than a traditional air to water heat pump. The boundary between heat networks and electrification in urban cores has not yet been meaningfully considered; managing the interaction between these vectors, legacy gas and any use of hydrogen is not yet under consideration.

The new Regional Energy Strategic Planners will have a role to play here, collaborating with DNOs and local authorities, but these have yet to be established. They will also need to factor in DESNZ's Heat Network Zoning initiative and a range of bespoke heat mapping projects undertaken by local authorities.

The challenge facing the RESPs becomes even greater when non-domestic loads are factored in. While a default assumption for electrification across most lower grade heat loads (e.g. catering, light manufacturing) is apparent in a range of model studies, this is a highly heterogenous sector with bespoke needs that are very difficult to manage centrally. High grade heat for a variety of end uses is likely to be provided via hydrogen, but for sites located away from hydrogen production facilities in industrial clusters the vector of choice is uncertain.

NETWORK COSTS

These are subject to exogenous factors that impact the costs of assets as well as the costs of capital, such as the recent inflationary pressures driven by Russia's invasion of Ukraine. Costs are currently on an upward trajectory following the combination of both higher overall capital costs plus an increasingly tight market for network components like switchgear. No full transfer from natural gas to hydrogen across a representative gas network area has yet been undertaken and therefore full costings for such a process are uncertain.

Historically, these have been estimated through Ofgem's benchmarking and engineering evaluation work, as well as independently by each DNO for business planning processes. Hydrogen transfer costs have been estimated from desk studies and limited trials.

CONSUMER TECHNOLOGY PREFERENCES

The majority of consumers have not faced a meaningful decision on the technology that heats their home in decades. This renders the evidence base for revealed consumer preferences – as opposed to expressed preferences in surveys – very slim.

While the Government's forthcoming Clean Heat Market Mechanism will include heat pump and hybrid technologies, consumer uptake of these technologies under the prior RHI scheme was significantly lower than that of biomass heating devices. While other countries in Europe have seen significant heat pump deployment, this includes widespread use of air to air devices less suitable for UK homes with an existing wet heating system. The political backlash against a boiler ban in Germany has also introduced a high degree of political risk into policy measures that are seen as moving faster than consumers are comfortable.

The Challenge Facing RESPs

Ofgem's Regional Energy Strategic Planner function is a step towards a mechanism that enables network investment through increased co-ordination and agreement between networks and LAs of future requirements. It does not fundamentally tackle the uncertainties facing the system and embeds fundamental assumptions about customer preferences into investment plans, assumptions that may prove expensive if they are incorrect. Nonetheless, it is clear that Ofgem sees their role as being an enabler of the kind of price regulation the RIIO regime represents.

The function as it stands sees the value of the RESP in being capable of 'whole system planning'; this is the thesis that there is an optimal plan for a system in a given region that manages the relationships between vectors and end uses in a way that is least cost. It is driven by the not unreasonable recognition that there will be occasions when assets relevant to one vector plan may have relevance to another; a heat network will need to know whether sufficient electrical or hydrogen capacity is available for its heat generator, a gas network will need to know where electrification of end use is likely to be faster in order to determine whether particular pipes need to be decommissioned, and an electrical network needs to know where hydrogen may be used for industrial heat to scale back plans for site electrification.

But taken as a totalising plan reveals that this approach is almost endearingly naïve. There are trade-offs implicit in the development of an energy network that have nothing to do with system optimisation and everything to do with who gets what resources – trade-offs that are inherently political in nature. Who gets the hydrogen production facilities with their associated jobs? Who gets the revenue from the extraction of heat from old pit works, and who gets the disruption from construction? Who gets an upgraded electrical connection first and so can be sure they're safe to buy an electric vehicle?

A plan that does not recognise and seek to manage these trade-offs is a plan that will be stuck in almost permanent delay. While the RESP will be obliged to engage local authorities who might be seen as a vehicle for doing so, planning will involve some choices that cut across LA boundaries. This places the RESP in the unpleasant situation of deciding which LA gets to win or spending many years managing negotiations.

Political Headwinds

A single consumer cannot do anything other than connect or disconnect to a network that runs adequately close by their property. They cannot through their purchases oblige a network company to maintain a particular medium pressure pipe or upgrade a transformer. Centralised ex ante planning will necessarily reduce consumer choice, whether in areas where the gas network is deprecated or where a heat network is installed as a de facto heating solution.

Homes and businesses will need to move away from fossil fuels for their cars and vans and for their heating and cooking. Such direct changes to people's lives must be seen as legitimate, or else they simply won't happen – either due to opposition at the polls or people just not buying what they are told to buy. Technocratic plans drawn up by NOs and Ofgem will not on their own suffice. Figure 9 illustrates the widespread desire for a choice in how people heat their home, regardless of what's optimal for the country as a whole.

This fundamental political challenge is not managed by Ofgem's proposed RESPs. This is an overtly technocratic organisation only meaningfully accountable to its regulator Ofgem, which in itself has only limited democratic oversight. This poses a fundamental risk to the transition to a low carbon energy system: there is no mechanism to ensure consumers agree.

In the absence of public support for a way forward, we expect politicians to prevaricate and delay. There is considerable evidence for this:

— **Clean heat market mechanism:**
BEIS first consulted on a market mechanism to support clean heat deployment in 2021. Despite promising the scheme for 2024, DESNZ only launched their second consultation earlier this year, to which they have just responded. While the CHMM will launch later this year, there will be no financial penalties for boiler manufacturers.

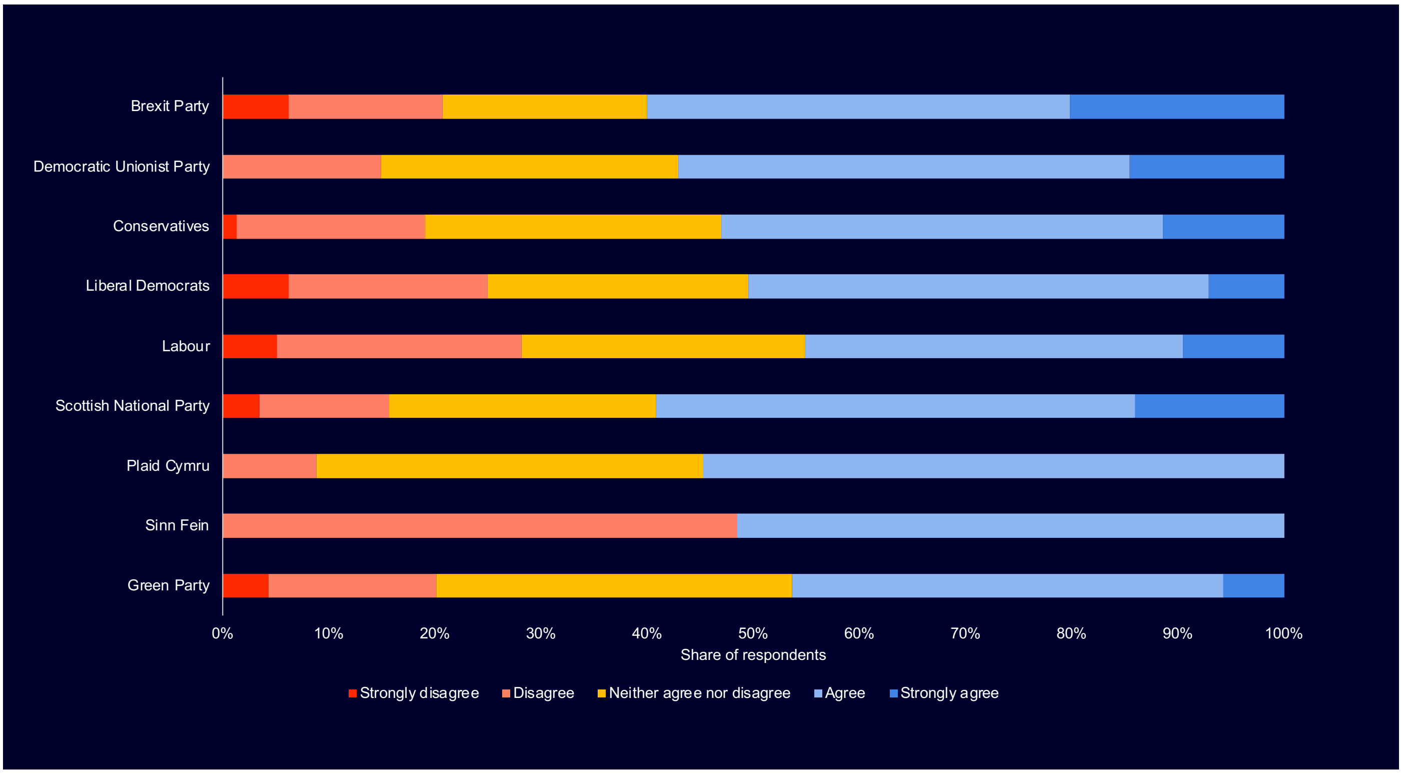
— **Review of electricity market arrangements (REMA):**
REMA was publicly announced in BEIS's April 2022 British Energy Security Strategy (BESS) after concluding there was a case for change. They consulted on options in late 2022, narrowed down their options in early 2023, and intend to consult again on options from March 2024, suggesting they will not conclude until at least two years after the project began. Over the same period, National Grid ESO published their case for market reform in November 2021 and published a set of recommendations from May 2022 (i.e. within six months) and into 2023.

— **Banning fossil fuels from off-grid homes:**
DESNZ launched a 2021 consultation planning to ban new off-grid boilers with effect from 2026. However, the response in October 2023 saw DESNZ reverse its decision and opt for a phase-out aligned with plans for on-grid boilers and allowing a 20% opt-out rate.

Delivering decarbonisation means creating frameworks for public buy-in when the public will be directly impacted. There is very little space in current proposals for this to happen.

At the end of this section, we pose the following question. Given the scale of uncertainty facing the regulator, is it still right to make cost prediction core to Ofgem's regulatory model? And, given the political challenges associated with seeking to reduce consumer choice to deliver certainty, is it even likely to be possible to do so?

Figure 9: To what extent do you agree with the following statement? 'I should be able to decide which energy source heats my home, even if it means higher costs for the country



05 ALTERNATIVES TO THE EVOLVING REGIME

We do not believe that the current framework for regulating and planning distribution networks will deliver the required volume of investment in a timely or cost-effective fashion. The level of scrutiny required under RIIO is overly burdensome and time-consuming, the political pathway for any given set of upgrades is unclear and there is insufficient flexibility in the regime to manage changing technological circumstances.

Furthermore, as currently configured RESPs will not be capable of unlocking the kind of politically secure plans that investment requires. As they evolve they will encounter even greater political pushback than the challenges facing the transmission network. Unlike high-voltage lines, they will be in peoples' neighbourhoods and have a say in what happens in their homes.

But what does it mean to propose an alternative to a regime that has gradually evolved over the course of thirty years since privatisation? We have sketched out above areas in which there are grounds to believe the framework is deficient; to present alternatives we will now lay out an anatomy of the regime to enable alternatives to be placed in this context.

PLANNING & INVESTMENT

As laid out in section 3, network planning is the result of DNOs taking future scenarios from the System Operator and iterating those scenarios against their existing network and the consumers they serve. Plans thus developed go into business plans which are agreed or not by Ofgem. RESPs will have the function of co-ordinating regional plans against a single version of the truth across all stakeholders in that region. Very simply, DNOs plan, Ofgem evaluates and decides.

COST CONTROL

In addition to planned investments, business plans set out operational expenditure as part of the total amount of money they will seek to recover from consumers. As networks are not subject to competition, Ofgem analyses and benchmarks their proposed costs against other DNOs and against the market, as set out in section 3. This is very much a negotiation between the DNOs and Ofgem, and frequently is adversarial in character. DNOs propose costs, Ofgem evaluates and decides.

TECHNOLOGY DEPLOYMENT

Policy on consumer incentives for low carbon technology is set by DESNZ. The Department determines the scale of ambition. The only meaningful exception to this are those local authorities developing heat networks, and some incentives provided by devolved administrations. While consumers have a role at the margin, the meaningful decisions about technology deployment are made by elected bodies.

POLITICAL CONSENT

While in theory the Secretary of State for DESNZ is accountable at the dispatch box for decisions made by the regulator for the purposes of network development, in practice the Secretary of State holds no formal power over the regulator beyond the ability to issue strategic policy statements. They have the ability to refuse planning consent to major grid projects or call them to public inquiry, but this power is only very rarely used and only rejects a particular version of that project rather than the spend agreed for it by the regulator. In practice no-one is responsible for ensuring political consent for network development beyond formal consultation processes baked into the planning system.

Our alternatives will therefore be specific changes to **who** makes the decisions set out above or how decisions are made.

This section sets out two alternative directions of travel, which are attempts to solve the twin challenges of radical uncertainty and lack of political consent. The first creates new democratic structures to manage political consent for network development, leaving much of the existing framework intact, and the second that replaces strategic or regional planning with a process of triggered investments, adapting to information as it arises: Pathway Planning.

05 ALTERNATIVES TO THE EVOLVING REGIME

Democratic Central Planning

In order to manage the politics of planning, a mechanism for regional public acceptability is required. Such a mechanism would need to explicitly find routes for ensuring the public have a say in the kinds of trade-offs any plan would involve. What 'a say' means is critical: the evidence we have from mechanisms of public engagement around infrastructure changes is that clarity around what can actually be changed and structured mechanisms for decision making is critical, as well as early engagement.[30]

Historic engagement over infrastructure in the UK, such as the Beauly Denny line[31] or the cancelled Mid Wales 400kv line[32] has revealed structural weaknesses in the approaches taken by infrastructure providers to public engagement. These contests were over individual projects; a region-wide plan would have the potential to upset hundreds of thousands of individual voters all at once.

For this alternative we place the responsibility for engendering political consent for a network plan in the hands of the RESPSs. We see three routes that they could utilise to manage public opinion.

01 Extensive Public Consultation

02 Citizen's Assembly

03 Votes on plans

01 Extensive Public Consultation

This de minimis option would see the RESP undertake engagement activities in every town, village and borough across its regions, developing a comprehensive picture of local wants and preferences. Not all of these preferences will be able to be satisfied at the same time, but their meaningful incorporation into a whole system plan – and explicit communication as to how they have been incorporated – will help to reduce political risk.

This option is within the existing tradition of governance in the UK and is how infrastructure planners have historically managed public engagement. We see any such activity managed by a RESP as having to be far more comprehensive and starting considerably earlier than any such activity has historically done to have a chance at success. However, given public engagement comes at a cost – and Ofgem will be regulating the costs of RESPs – there is a considerable risk that inadequate weight is placed upon this function and public consultation ends up inflaming opinion more than quell it. Moreover, consultation by itself does not provide a reasonable structure for engaging with decisions on trade-offs meaningfully; it merely provides a route for voters to voice their concerns but without a guarantee they will be listened to.

02 Citizens' Assembly

This is a particular mechanism for developing solutions to problems that has been utilised across conversations around decarbonisation and beyond.[33] Citizens, selected on the same basis as jury service, are provided with expert support and asked to make decisions on the explicit trade-offs that any plan would represent. The theory underpinning this model is that decisions made by fellow citizens are more acceptable to the general public than choices made by distant technocrats on the grounds that they better reflect the actual concerns of the public. This has been borne out in a number of settings, including on the abortion debate in Ireland, an arguably considerably more politically challenging topic than network planning.[34]

The difficulty facing such a model is the complex technical nature of energy system planning. It is not clear that such an assembly would be capable or have the capacity to plan individual upgrades down to the neighbourhood or indeed street level. For this route to work effectively, the RESP would need to undertake a significant volume of the planning effort and expose only those areas where trade-offs are significant to the Assembly, which by itself could be seen as limiting public oversight. It is also unclear whether the same kind of public interest test that makes mandatory service on juries publicly acceptable would apply to such a body.

03 Votes on plans

While the national Government at Westminster has legislated for Net Zero, there is considerable scope for each region to chart its own path towards that target. Rather than having a single 'whole system plan', multiple organisations could be given scope to develop their own. These organisations could include the existing energy networks, large scale engineering organisations, and potentially a Citizens' Assembly established as under (2). Plans thus prepared could then be put to a vote.

How the public could review these plans – and how they would be differentiated – depends upon the region. We assume that plans would be costed and that these costs would be made transparent, further that any costs would be independently evaluated. Where this differs from the Citizens' Assembly option in large part is that we assume independent media – or competing campaigns for plans – could be relied upon to ruthlessly scrutinise the plans on offer and highlight the trade-offs they involve.

Such democratic scrutiny of the kind typically applied to rather less detailed party manifestos would be a first for the UK; a 2012 initiative to hold a referendum on a proposed bioenergy plant in Southampton was scrapped owing to increasing costs.[35] To verify that this kind of decision can be taken electorally and produce a meaningful result, we would recommend piloting this approach in an appropriately representative area.

Under all these models the anatomy of our regime changes. The planning role explicitly moves from the DNOs to the RESPs, although in practice we would expect any such plans to be co-created. However, under (2) and (3) the legitimacy of Ofgem's decision-making on investments would become unclear. Would it be appropriate for the regulator to refuse to admit funding for a particular investment that has been decided on by a Citizens' Assembly, much less a public vote? Under these models, we therefore assume that Ofgem's role is to evaluate and independently assess costs of plans, but the decision to invest to be taken by the assembly or by the public.

Further, under (3) we would expect the role of existing elected bodies in determining technological outcomes to be gainsaid. Implicit in a region opting for an electrical solution in a particular area must be some form of support for consumer purchases of that solution, and similarly for networks transitioning to hydrogen; the form of this support goes beyond the scope of this paper. Technological decisions made by central Government that are seen to override a decision explicitly made through a vote by the public will have little legitimacy.

A regulatory challenge facing all of these options is what, exactly, a plan entails. The description 'whole system plan' used by Ofgem implies such plans would dictate the fate of all the wires and pipes plus generation, production and transformation of energy vectors necessary to make an entire system work over the twenty-year period up to Net Zero. This is almost certainly too long a period to make meaningful choices given the uncertainties covered earlier in this paper, and as a result plans should most likely be constrained to ten years at most. This reflects the existing ten year statement framework.

However, the key challenge facing this approach in its entirety is that it does not actually lock in public agreement. It still involves some form of imposition of a solution on members of the public who may have voted for something else. Especially for heat, so fundamental to our understanding of our homes, it is not at all clear that the public will countenance their right to decide what to do in their home being decided by the vote of their neighbour.

Despite this, democratic planning with its varying levels of radicalism represents a logical path for maximising public agreement for any given energy plan. In the absence of an alternative route we expect Ofgem to mandate RESPs to undertake a version of (1) above, especially given that the alternatives would represent a considerable forfeit of its authority. We do not believe such an approach would be effective for the reasons set out above, and the alternatives forms of democratic oversight we have outlined we expect to be viewed as too radical for the sector. We therefore turn to our preferred option.

Pathway Planning

Fundamental to this option is the insight that investment in new infrastructure can only be justified when enough information is available – but that once that information is available investment should proceed at pace.

For inspiration we have turned to the water sector, and the Adaptive Planning approach endorsed by DEFRA and by Ofwat in its guidance to water companies on how they should undertake long-term planning. Adaptive planning's theoretical underpinning is the recognition that actively seeking out information is part of the way in which participants in markets secure advantage. Creating a shared version of that information overcomes the challenge of information asymmetry that bedevils economic regulation.

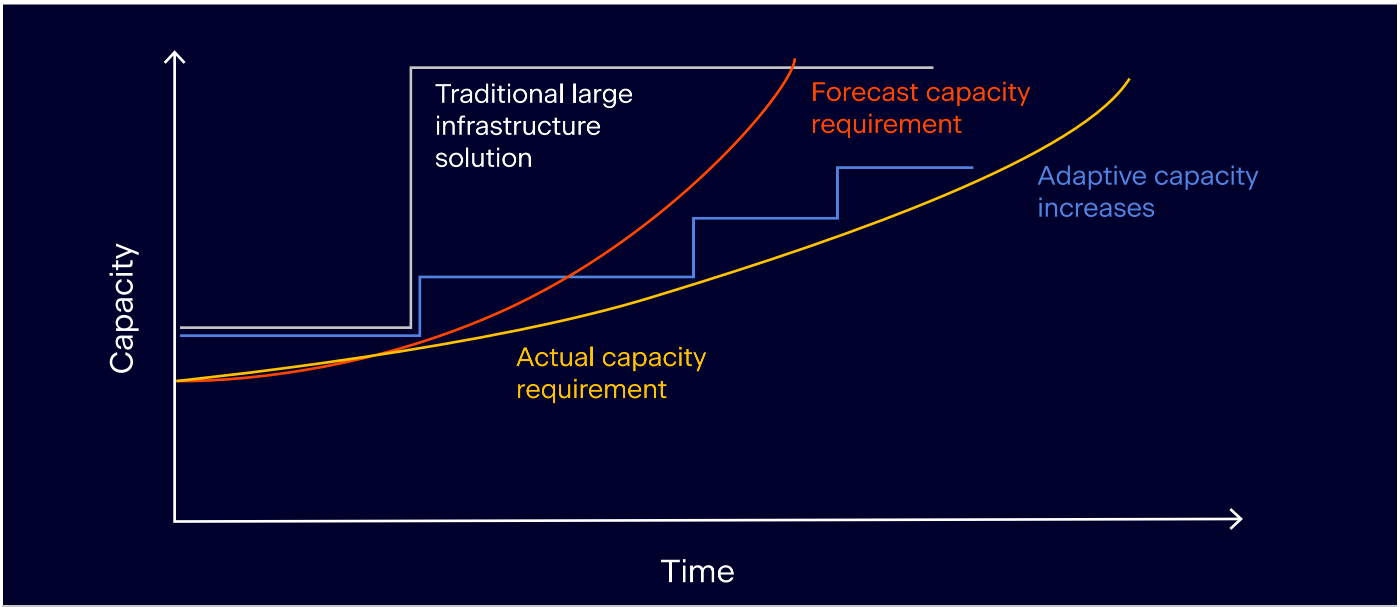
Figure 10 demonstrates adaptive planning compared to traditional large infrastructure solutions. The investor can see two future outcomes (red and green lines) but is unsure which will materialise. Undertaking a large investment (grey line) would provide enough capacity for either scenario but may not be needed under the green scenario, meaning consumer money is wasted. Undertaking more modular investments (blue line) maintains the option of meeting the larger capacity requirement (red line) but allows major investment decisions to be delayed until the future is more certain.

Adaptive planning, as envisaged via Ofwat, exclusively concerns longer-term planning rather than choices made within a price control cycle. The expectation is that this will enable a traditional heavy-oversight framework to continue even under uncertainty. The approach we propose, Pathway Planning, differs in two key aspects:

01 Considerably shorter timelines for decision-making that enables choices to be made within a control period. This is driven by the greater level of change facing energy networks. To illustrate this, the ED3 price control period will cover 2028 to 2033. During this period heat pump ownership could increase from what is currently a rounding error to nearly a third of homes if the UK follows the CCC's Balanced Net Zero pathway.

02 This much greater pace of change comes with much greater complexity too; the outcomes are not about transmission-level investments but investments at a neighbourhood level. For this reason the large-scale scenario analysis advocated by Ofwat is not adequately granular, and we advocate instead a set of probabilistic **pathways** that are more amenable to local iteration.

Figure 10: Adaptive solutions versus traditional large infrastructure solutions



Source: PR24-and-beyond-Final-guidance-on-long-term-delivery-strategies_Pr24.pdf (ofwat.gov.uk)

To illustrate how it could work, first consider how the above domestic heating challenge would impact networks. For the purposes of network planning to serve domestic heating loads there is a set of outcomes for a given area that can be exhaustively anticipated in advance:

01 An entirely electric solution with heat provided by heat pumps;

02 An entirely electric solution with heat provided by a range of electrical technologies;

03 A partially electric partially hydrogen solution with heat provided by hybrid devices; Biomethane could conceivably play a role instead of hydrogen in this scenario, although most likely only in areas very close to agricultural land where exporting biomethane has particular challenges;

04 A solution in which hydrogen provides the majority of heat through household level devices;

05 A heat network solution in which the primary heat generator is a large heat pump, or;

06 A heat network solution in which the primary heat generator is a hydrogen boiler or CHP.

The key question facing a Pathway Planning approach is **what information makes a given outcome more likely in a given area.** A predominantly rural area with multiple households at the ends of individual network connections will never be suitable for a heat network for example. In a suburban area in which 66% of households have installed a heat pump the likelihood that hydrogen will be an appropriate solution is very low and therefore a comprehensive electricity network upgrade is in order. Similarly, if by 2040 only a very small number of households have installed heat pumps and are still reliant on gas – and replacement cycles there is no time for consumers to switch themselves – a hydrogen solution in that area becomes effectively the only likely path for decarbonisation.

These are explicitly probabilistic statements in which the likelihood of an outcome for a given area is determined by consumer choices and/or the network topography of that area. They are framed in such a way that as consumer preferences develop the likelihood of a given outcome in that area changes. If we develop a set of these statements sufficient to cover the entire range of potential outcomes in every area of a given region, we will have defined the entire territory over which potential investments can be anticipated. We can then specify the thresholds for consumer outcomes under which certain investments can be made. Importantly, the kinds of trade-offs that democratic accountability is necessary to manage fall away: outcomes are dependent on consumer choices rather than central planning.

THE BRANCHING PATH

Under Pathway Planning the role of RESPs is not to specify a single plan, but rather to establish a branching pathway of potential outcomes across the territory they cover, agreed with both DNOs and local authorities. Within these pathways the RESPs should specify the thresholds under which certain investments are triggered to enable those investments to be made without recourse to Ofgem's re-opener process. The RESPs are then responsible for monitoring whether these thresholds have been reached and continually reassessing the probability of a given outcome over time. This means that decisions on a class of uncertain investments are explicitly taken out of Ofgem's hands and instead taken on the basis of a framework determined by the RESPs.

Figure 11: Current evolving framework versus pathway planning

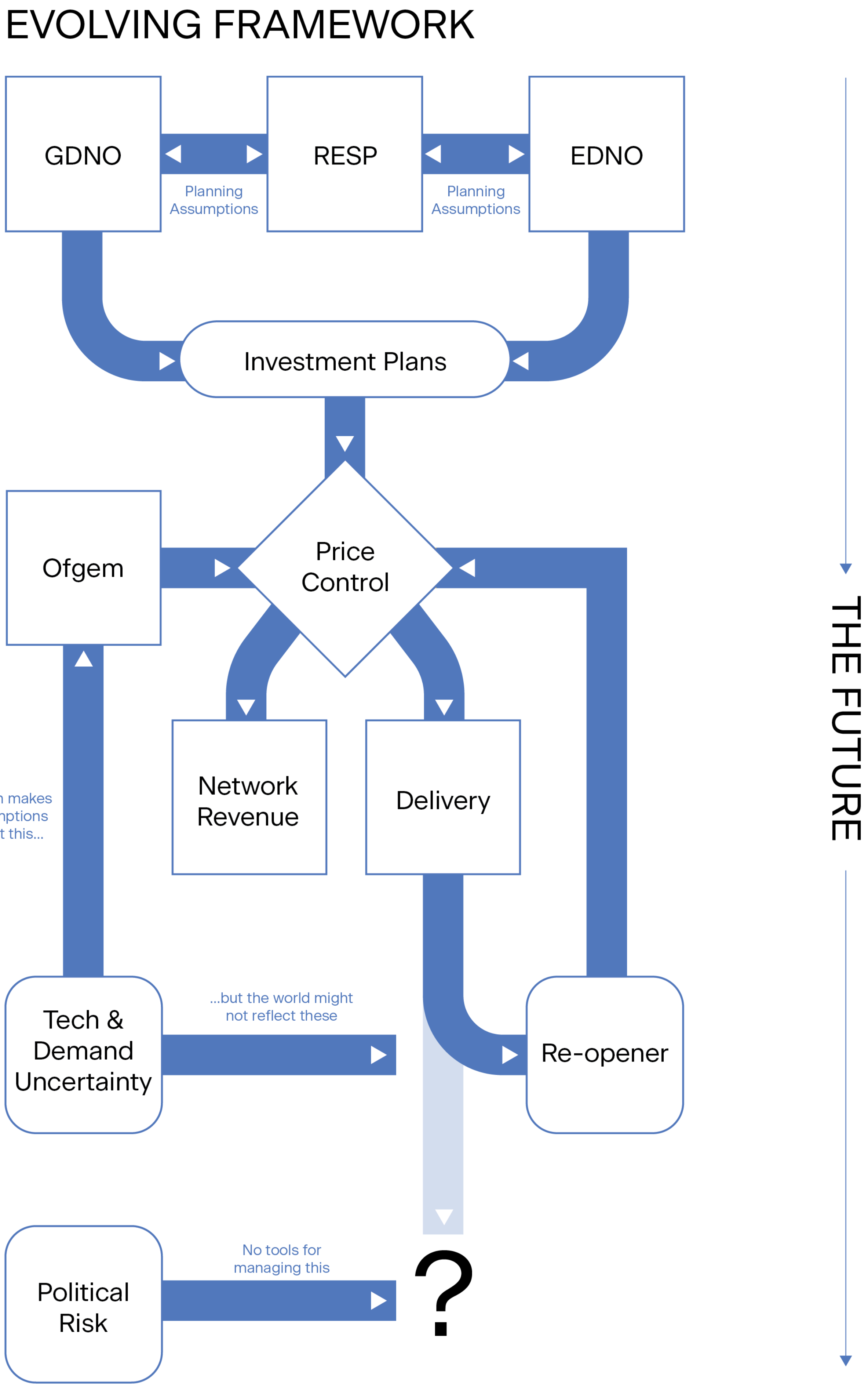
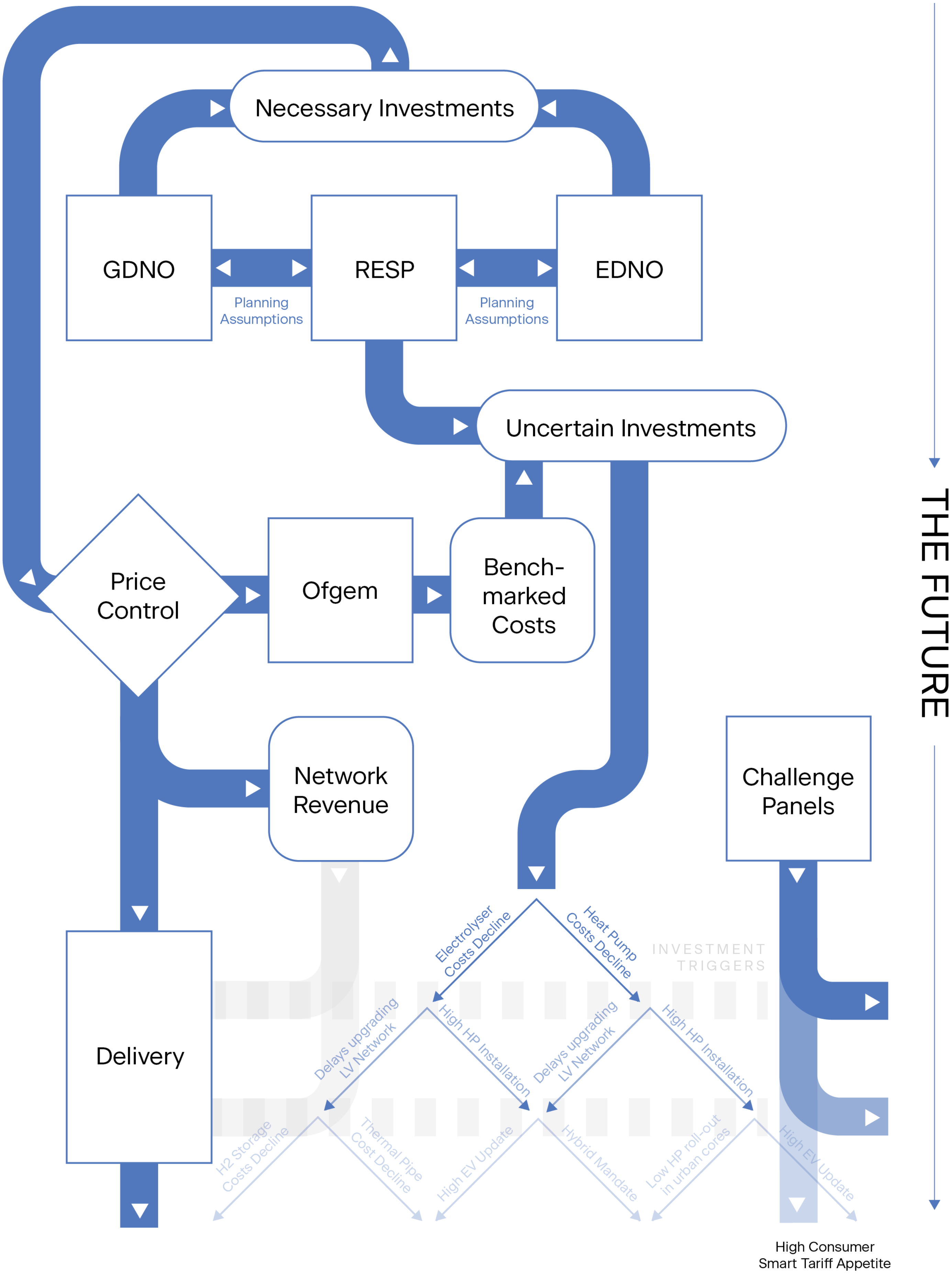


Figure 11: Current evolving framework versus pathway planning

ILLUSTRATIVE PATHWAY FRAMEWORK



This route enables consumer preferences to be the dominant force in determining network outcomes; it gives scope to consumers to vote with their wallets. But it can also incorporate non-consumer information. Changes in the cost profiles of key technologies – such as heat pumps, electrolysers, heat network piping and controls – will also affect the probabilities of particular outcomes and can be incorporated into the ongoing assessment undertaken by the RESP. Critically, it can also internalise the outcome of key technological experiments, such as hydrogen safety trials. This manages the uncertainties laid out above without requiring assumptions about the future.

But consumers are not the only stakeholders who care about the delivery of network infrastructure. This is reflected in the existing regime through the use of challenge panels involving representatives of consumers, customers for network connections like industry, academics and NGOs. These bodies have a role in advising Ofgem during the price control process, seeking to ensure the interests of the parties they represent are taken into account. Whether they have been successful is subject to considerable debate; certainly, the fact that Ofgem appoints them has been taken as a sign that they are not as independent as they might appear.

Under Pathway Planning, we would recommend an alternative role for these panels in providing additional scrutiny of RESP's branching pathways and investment triggers. Business customers will have an interest in ensuring connectivity for their projects, NGOs will have an interest in ensuring that environmental impacts are proportionate, and consumer groups will have an interest in ensuring that costs are controlled. The purpose of these groups is to develop trust between the participating parties, the RESP and the networks; we would therefore anticipate their role and their structure to evolve over time as all parties gain a greater understanding of each other.

AGREEING INVESTMENT REQUIREMENTS

Under the existing regime, NOs submit their 5-year plans to Ofgem in advance of each price review. The process would remain largely the same under Pathway Planning. NO plans would need to consider the full range of future capacity needs in their licence area, identifying:

— which needs are common across multiple pathways;

— dates at which they may have better information about the likelihood of each outcome ('decision points');

— the costs of their portfolio of possible investments across each pathway, and;

— what incremental investments are available to meet capacity needs until decision points are reached.

These investments should allow network capacity to meet supply and demand projections from the System Operator and the RESP.

As custodians of consumers, Ofgem have an incentive to minimise network investments in order to keep down bills (subject to meeting consumer's energy needs). Pathway Planning should in theory make this easier, inasmuch as it enables investment to be purely responsive to consumer choices. Determining costs across multiple pathways rather than a single pathway may represent an increased burden, and so a preferable approach may be determining a set of generic project costs as part of the business planning process rather than seeking to exhaust a potentially vast probability space.

Investments triggered during a price control period would feed back into network charges at the next review of charges, pending a more automatic mechanism. There is no role here for Ofgem to second-guess the RESP's framework; to do so would defeat the point of the regime.

PINNING DOWN FUTURE OUTCOMES

Pathway Planning relies on incremental investments to meet capacity needs until more information about the future is available. This information may appear purely through the passage of time – e.g. learning more about future economic growth, or in the case of a non-energy project like the Thames Barrier, the degree of climate change and sea level rises. Pathway Planning could lead to higher consumer bills: a succession of iterative investments may be justified if the need for a large piece of infrastructure is uncertain. But should it emerge that the large piece of infrastructure is in fact needed, the iterative investments will still have occurred and need paying for.

It therefore makes sense to invest in collecting information. Pulling forward 'decision points' can reduce the need for more iterative investments and the risk of building stranded assets. For example better understanding consumer preferences for different low carbon technologies can help refine scenario planning as preferences will drive likelihoods, although they are no substitute for actual buying decisions.

Ofgem, RESPs and the NOs could use local experiments to gather more information. These could test using waste industrial heat for heat networks, or novel ways of managing network capacity headroom beyond investment in traditional assets. By improving our understanding of the likelihood of different scenarios, running local experiments can complement an Pathway Planning regime through narrowing down the range of scenarios of future capacity requirements.

The regime for these local experiments already exists in Ofgem's energy regulation sandbox,[36] and consumer acceptability for low carbon technologies is already being tested via the Hydrogen Village Trial and the ESO's Demand Flexibility Service.[37] Further experiments could test acceptability of other heating technologies, of using waste industrial heat; or consumer's views on using EVs as batteries for the grid.

PATHWAY PLANNING COMPARED TO EXISTING RE-OPENERS

Under the current periodic price review regime, NOs submit the key uncertainties during the price review process they may face and, following consultation and negotiation with Ofgem, 'common' and bespoke uncertainty mechanisms are created. Under RIIO-ED2, there are 37 common and 7 bespoke uncertainty mechanisms. There are five main types of uncertainty mechanisms that are used in the RIIO-2 price control:

— Volume drivers to adjust allowances in line with actual volumes where the volume of work required over the price control is uncertain (but where the cost of each unit is stable)

— Re-opener mechanisms to decide, within the price control period, whether changes in allowances are needed, eg. to deliver a project or activity once there is more certainty on the needs case, and costs

— Pass-through mechanisms to adjust allowances for costs incurred by the network companies over which they have limited control, eg business rates

— Indexation to provide network companies and consumers some protection against the risk that outturn prices are different to those that were forecasted when setting the price control, eg general price inflation or sector specific cost pressures

— Use-it-or-lose-it allowance to adjust allowances where the need for work has been identified, but the specific nature of work or costs are uncertain.

Ofgem principally relies on the following re-openers when scrutinising investments to decarbonise the system:

— The Net Zero reopener

— The Net Zero pre-construction and small projects re-opener

— The Net Zero and re-opener development 'use-it-or-lose-it' allowance

— The Environmental Legislation re-opener

However, these re-openers are based on the assessment of uncertainty at the beginning of the 5-year price control and hence are not very flexible. The uncertainties in these mechanisms are also not always clearly defined and NOs are not encouraged to provide enough explicit detail of them, reflecting the lack of long-term coordinated planning that accounts for uncertainty.

This leads to large investments being based on uncertain assumptions of future demand and frequently needing to make use of highly costly re-openers when costs overrun or become sunk. Applying for the use of re-openers is also an administratively burdensome task between the NOs and Ofgem. The process itself is burdensome and Ofgem has to assess using often only loosely defined terms for re-opener qualification.

The overall difference then between the current regime of re-openers and Pathway Planning is thus the difference between reacting to uncertainty in an inflexible system and proactively adapting to uncertainty in a more detailed, responsive manner respectively. More specifically:

01 The level of explicit detail when planning for uncertainty. Meeting net zero goals will inherently include a large amount of uncertainty. Pathway Planning will make NOs explicitly include the effects of these future uncertainties into their business plans making them better prepared for future challenges and making it easier for the regulator to adapt price controls.

02 The level of flexibility and speed of decision-making as the circumstances under which an alternative pathway will be followed and the point at which the decision to change to the alternative pathway will have already been detailed in the business plan. This will reduce the need for drawn-out processes and negotiations over re-openers, as well as the need for Ofgem to scrutinise Engineering Justification papers.

03 The level of transparency of NOs business plans. The Pathway Planning framework proposed here enforces companies to provide significantly more detail in their business plans in terms of what their future goals are, what they believe are the best pathways to meet them and what metrics they are using to monitor progress.

04 The potential for reduced costs to consumers. The higher level of detail required in the initial business planning stages may require more resourcing which may ultimately increase cost to consumers in the short term. However, Pathway Planning can mean that expenditure more closely reflects future requirements. Instead of building projects based on uncertain future demand, expenditure can be spent on projects based on more certain outcomes hence reducing the potential for overspending and asset stranding. This could reduce the use of re-openers and reduce cost to consumers in the long term.

REGULATORY OPTION VALUE AND DECOMMISSIONING BONDS

One of the key challenges that an alternative to RIIO would need to manage is existing assets that have value in one set of outcomes but have zero value in another. The principle example is the gas network. In areas currently using natural gas for heat but that have a high likelihood of transitioning to a non-gas heat solution the long-term value of the relevant set of pipes is not clear.

Ofgem sought to manage this in RIIO GD-1 by fixing the depreciation period for investments made after 2002 to 45 years and front-loading some of this cost. This depreciation period was maintained for RIIO GD-2, meaning that investments made in 2026 could be recovering their costs until 2071.

The current regulatory framework has no mechanism for distinguishing between assets that have a long useful life and ones which will be rendered redundant by consumer preference for alternative technologies. Pathway Planning offers a pathway to manage this, by identifying those assets with a high probability of having an enduring role and allocating them a particular status. Very broadly, existing gas assets fall into one of three categories:

01 **Highly Likely** to be required in 2050, determined by role in e.g. industrial sites or proximity to hydrogen/biomethane production facilities;

02 **Potential** to be required in 2050, depending on cost outcomes and consumer preferences for alternative heating technologies.

03 **Unlikely** to be required in 2050, these are assets at the edge of the network or in areas with upgraded electrical infrastructure and high levels of heat pump deployment.

It should be clear that investments in assets in category 1 can be appropriately depreciated over the timescales specified in Ofgem's existing price control framework. The same does not apply to the second two asset categories. Where an RESP's branching pathway indicates an asset falls into category 2, investments made into this asset such as mains replacement should not be added to RAV. Rather, a new category of regulatory value could be established: Regulatory Option Value. This represents an asset that the regulatory system maintains while its future is uncertain and therefore needs to pay for.

Assets in ROV contribute to returns and depreciate over typical periods while the relevant RSP considers the likelihood of their future use to be over a given threshold. In the event that those assets move into category 1, they are added to RAV. In the event that they move into category 3, they are placed into an accelerated depreciation profile, potentially as short as ten years. This prevents future customers from being charged for an asset which no longer exists, while providing investors with confidence that they will recover their investment in the event it is found to no longer be required.

For gas assets that are no longer required and can be safely disconnected from the rest of the system, it is not enough to simply abandon pipes in the ground. Above ground infrastructure, including pipes that enter homes and non-domestic buildings, need to be capped off and made safe. Pipes with a pressure higher than one bar could suffer significant structural weaknesses when they are no longer being held under pressure and would need to be either filled with pressurised air or with concrete. Enduring risks from remaining service pipes would need to be managed by a dedicated agency.

It would not be appropriate to charge remaining gas or hydrogen customers for this expenditure, and therefore an alternative route for recovering these costs is necessary. Government may choose to simply buy non-depreciated assets at their book plus asset value from gas networks or make provision to finance decommissioning and any enduring depreciation costs by issuing Decommissioning Bonds to pay down the cost of doing so. This enables investors to continue to fund critical safety upgrades to gas networks in the confidence that regardless of the outcome at the end of a branching path they can recover their investment.

06 CONCLUSION

Delivering Net Zero on time and at least cost is the single most important policy challenge of this generation. In the face of this challenge – and the tremendous technological uncertainty it represents – the right response is humility. Considerable time has been spent by officials in Whitehall and the regulator on what the future will look like and attempting to devise plans and policy accordingly. What we have sought to argue in this paper is that this is both mistaken and likely unnecessary.

Particularly in the context of network regulation, the amount of uncertainty that needs to be overcome to guarantee the probity of any particular investment is too high. But we cannot let this delay decision-making, and we therefore must change our approach to one that does not attempt to anticipate the future so much as one that seeks to structure the array of potential outcomes we might face, and to act accordingly.

While we build the case for this move, we believe the right next step is for the developing RESPs to be given the capability to undertake the kind of probabilistic analysis we outline and for this to be baked into their function from the outset. This provides the necessary intellectual machinery for a future transition to a Pathway regime.

Adaptive planning is a radical shift in how the UK thinks about energy networks, but it is one that we believe enables decisions to be made in a timely fashion and to give us the best chance at holding down the costs of any transition. The regime is not without risks, but the primary risk to which it is subject – that of the misallocation of capital – is one that is also present in the existing regime. Adaptive planning on the model we outline makes this risk explicit by placing a number on it, and thus gives officials and network operators new tools to manage this risk. As the regulator develops RIIO 3 and the function of the RESPs, we believe it is the right time to start a debate about whether that framework is right one to deliver the infrastructure we need to decarbonise Britain.

ANNEX - INTERNATIONAL APPROACHES TO ENERGY REGULATION

AUSTRALIA

The Australian Energy Regulator (AER) regulates wholesale and retail energy markets, and energy networks in Australia. The AER's overarching objective is to contribute to achieving the "National Electricity Objective" and "National Gas Objective": "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to: price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system." and "to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The AER determines the revenues for electricity distribution and gas distribution networks, for electricity transmission networks, and for some natural gas transmission pipelines (They do not regulate utilities in Western Australia). The AER generally determines a revenue cap for each of the utilities it regulates— meaning that the utility can collect the revenue that the AER authorises, independent of whether the quantity of services provided turns out to be higher or lower than expected in each year. The revenue determination for each utility lasts five years.

The AER's overall approach to rate of return is to use the CAPM to determine the cost of equity, and to estimate a cost of debt equal to a historical average of a benchmark corporate bond index. This bond indexing accounts for changes to inflation over the regulatory period.

The regulatory framework requires the AER to include all actual capital expenditure in the rate base (and therefore to provide a return on and of this investment), provided that the capital expenditure in the prior regulatory period was less than that approved by the AER at the start of that prior period. Capital expenditure above the previously-approved level can be excluded from the rate base if the AER considers that the extra investment was not efficient.

ITALY

The Italian Regulatory Authority for Energy, Networks and the Environment (ARERA) is responsible for regulating the Italian energy system. Their regulatory scope in the energy sector includes transmission and distribution of electricity, and transmission, distribution, metering, storage and regasification of natural gas. This is a complicated system with many small players. There are about 130 electricity DSOs and 210 gas DSOs operating in Italian regions and provinces, organized with a wide range of legal forms, from listed companies, to privately-held companies, to publicly-owned entities.

ARERA's overall objective is to promote competition and efficiency in public utility services and to protect the interests of users and consumers. To do this, ARERA determines a rate of return based on their assessment of revenues and tariffs. These regulatory periods last for six years, although every three years some of the financial modelling is updated to reflect any changes to inflation, the risk free rate, and market risk premiums.

ARERA determines authorised revenues based on a regulatory asset base that is indexed to inflation. Authorised revenues are set based on a "building blocks" approach, with depreciation, operating costs, an authorised return on the capital employed as components of the authorised revenue. They use a pre-tax WACC, so there is no need for a tax building block.

NETHERLANDS

The Netherlands Authority for Consumers and Markets (ACM) is the regulator for energy networks and other infrastructure in the Netherlands. The Dutch government owns the majority of the utilities that the ACM is responsible for regulating, although ACM operates independently.

The ACM is responsible for determining the regulatory method for the determination of tariffs, including the appropriate return on invested capital. ACM is tasked with establishing a method whereby the regulated companies have an incentive to act as efficiently as they would in a competitive market, with sufficient financial incentives for quality and efficiency improvement. Additionally, the ACM must take into account the importance of security of supply, the importance of sustainability and the importance that network operators can realize a reasonable return on investments.

The regulatory revenue determination set by the ACM lasts for five years at a time and is derived on an inflation index regulatory asset base. The revenues allow the regulated network to recover capital depreciation and operating costs, including a return on the invested capital. The ACM determines the WACC at the beginning of each regulatory period, and determines the revenue for the next five years at the same time. The way the regulatory method is implemented requires the ACM to determine the WACC for two points in time: a WACC for the year before the start of the regulatory period and a WACC for the final year of the regulatory period. The ACM interpolates between these figures to calculate the WACC for each year in the 5-year window.

The ACM uses a single common methodology across gas and electricity transmission and distribution networks at the beginning of the 5-year regulatory period. The current regulatory window runs through till 2026.

Challenges and appeals can be made against a revenue determination. If successful, an appeal may lead the ACM to revise its method decisions and to update its rate of return methodology for subsequent regulatory periods.

NEW ZEALAND

The New Zealand Commerce Commission (NZCC) regulates energy networks and other infrastructure in New Zealand. The NZCC is also responsible for monitoring all consumer markets, some examples include supermarkets, airport services, telecoms, and the dairy sector. The NZCC's objective is protecting consumer interests and promoting competition. While market efficiency is not explicitly mentioned as their objective, it can be expected as an outcome of promoting competition (and that encouraging efficiency would protect consumer interests). These objectives are more similar to the objectives of Ofgem than most other Western countries.

New Zealand's electricity sector consists of a single state-owned transmission network operator, Transpower, and roughly 30 Electricity Distribution Businesses (EDBs), slightly over half are investor-owned and the rest are consumer-owned. The NZCC sets prices for the investor-owned EDBs and Transpower, as well as one gas transmission business (First Gas) and four gas distribution businesses (GPBs). While consumer-owned status exempts these EDBs from price-quality regulation there are still certain requirements in set by the NZCC which consumer-owned EDBs must follow.

The NZCC publishes three different price-quality regulatory schemes. All three schemes have rate of return parameters set in the same way, but differ in other details. The three schemes are:

a) The Default Price-quality Path (DPP) regulation for GPBs and investor-owned EDBs based on a 5-year regulatory period.

b) The Individual Price-quality Path (IPP) regulation for Transpower, which typically is based on a regulatory period of 5 years but allows for a 4-year period.

c) GPBs and EDBs can apply for a Customised Price-quality Path (CPP) if they consider that the DPP is not appropriate, given the specific circumstances facing that business. CPPs apply for regulatory periods of 3 to 5 years. Typically, there are only a few CPPs.

The price-quality path approach is similar to frameworks in other jurisdictions (The UK and Australia) with five-year revenue caps, although the NZCC relies to a greater extent on standardized annual reporting of relevant regulatory accounting information, rather than a "proposal" from the utility.

USA

The Federal Energy Regulatory Commission (FERC) regulates interstate natural gas pipelines and electricity transmission in the USA. FERC does not regulate gas or electricity distribution (this is the responsibility of individual state regulators and varies state-by-state). The FERC's overall objective (and the legal standard for its decision-making) is that utility rates must be "just and reasonable". In practice, FERC seeks to set a rate of return which is equivalent to what investors could obtain elsewhere from investments of similar risk.

Unlike many other regulators in this space, FERC determines maximum prices, rather than maximum revenues. However, for both natural gas pipelines and electricity transmission utilities, most revenue comes from charges for capacity rather than throughput. This means that in practice there isn't a significant difference in terms of revenue risk despite the different target of regulation.

Another area of difference in the USA compared to other similar countries is that FERC does not determine revenues or the rate of return for a pre-specified five-year period. FERC proceedings can be launched any time that customers, the utility, or FERC itself thinks that rates should change. In practice, this means that some FERC-regulated utilities can go for many years between rate cases. This can sometimes cause issues during periods of high price volatility as the FERC methodology does not index to inflation.

However, FERC's rate of return methodology at a given date is the same independent of the length of time since the last rate case. This is intended to help reduce regulatory burden. In practice, the FERC's rate of return decisions can be and are sometimes appealed to the courts, which in recent years have caused several changes to the rate of return methodology and an increase in the regulatory burden.

ENDNOTES

1 Germany passes watered-down 'boiler ban' law after months of infighting
2 Stern, J., 2003, "What the Littlechild Report Actually Said", Regulation Initiative Working Paper, No. 55, https://www.regulation.org.uk/library/2003-Jon_Stern-What_the_Littlechild_Report_Actually_Said.pdf
3 https://www.eprg.group.cam.ac.uk/wp-content/uploads/2019/10/S.-Littlechild_1983-report.pdf
4 https://www.eprg.group.cam.ac.uk/wp-content/uploads/2020/06/S.-Littlechild_Submission-to-CMA_June2020.pdf
5 Regulating energy networks for the future: RPI-X@20 decision document | Ofgem
6 Project Discovery - Energy Market Scenarios | Ofgem
7 p 48, Project Discovery - Energy Market Scenarios | Ofgem
8 https://www.ofgem.gov.uk/publications/handbook-implementing-riio-model
9 RIIO-ED1 Network Performance Summary 2020-21 (ofgem.gov.uk)
10 Network Options Assessment (NOA) | ESO (nationalgrideso.com)
11 Network Options Assessment methodology review and related direction (ofgem.gov.uk)
12 Large Onshore Transmission Investments (LOTI) Re-opener Guidance | Ofgem
13 Decision on accelerating onshore electricity transmission investment (ofgem.gov.uk)
14 Ofgem, Decision on accelerating onshore electricity transmission investment, December 2022
15 Decision on accelerating onshore electricity transmission investment | Ofgem
16 Decision on the initial findings of our Electricity Transmission Network Planning Review (ofgem.gov.uk)
17 download (nationalgrid.com)
18 Electricity Networks Commissioner: companion report findings and recommendations (publishing.service.gov.uk)
19 Gas Ten Year Statement (GTYS) | National Gas
20 Decision on the initial findings of our Electricity Transmission Network Planning Review (ofgem.gov.uk)
21 Our RIIO-ED2 Business Plan - SP Energy Networks
22 Heat network zoning - GOV.UK (www.gov.uk)
23 Estimate includes the DAs, Greater London, Cambridgeshire & Peterborough, West Midlands, Greater Manchester, West Yorkshire, East Midlands, South Yorkshire, Liverpool City Region, North East Region, West of England, Tees Valley, and North Yorkshire.
24 E.g. whilst the Greater London Authority has had significant control transport via Transport for London (TfL), the Greater Manchester Combined Authority has only this year been given 'influence' over regional rail services. Meanwhile whilst the Mayor of London can also be an MP (roles both Ken Livingstone and Boris Johnson temporarily combined), Tracy Brabin had to stand down as an MP to stand for Mayor of West Yorkshire as the role includes the powers of a Police and Crime Commissioner.
Greater Manchester strikes trailblazing new devolution deal – "New era for English devolution" - Greater Manchester Combined Authority (greatermanchester-ca.gov.uk)
Labour MP will step down if elected mayor - why a win for Tracy Brabin could spell disaster for Keir Starmer (nationalworld.com)
25 Ofgem green lights regional energy planning roles to speed up net zero transition | Ofgem
26 P000358 1..8 (stanford.edu)
27 13 years passed between a coordinated approach to offshore networks being proposed and implemented.
Offshore transmission network review - GOV.UK (www.gov.uk);
https://www.ofgem.gov.uk/sites/default/files/docs/2012/03/20120103_otcp-conclusions-report.pdf
28 Accelerating electricity transmission network deployment: Electricity Networks Commissioner's recommendations - GOV.UK (www.gov.uk)
29 Executive summary – Electricity Grids and Secure Energy Transitions – Analysis - IEA
30 See e.g. INSPIRE-Grid (renewables-grid.eu)
31 Beauly-Denny power line dividing opinion 15 years on from public inquiry (pressandjournal.co.uk)
32 National Grid Mid Wales Connection Project - Projects - Gillespies
33 E.g. Climate Assembly UK
34 The Irish abortion referendum: How a Citizens' Assembly helped to break years of political deadlock – Electoral Reform Society – ERS (electoral-reform.org.uk)
35 Southampton biomass: City council stops referendum - BBC News
36 Energy Regulation Sandbox: Guidance for Innovators | Ofgem
37 Demand Flexibility Service delivers electricity to power 10 million households. | ESO (nationalgrideso.com)

STONEHAVEN