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NET ZERO: An International Review of Electricity and Natural Gas Delivery System Policy and Regulation for Canadian Energy Decision-makers

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Michael Cleland and Monica Gattinger would like to thank the senior practitioner advisors who provided guidance at key points in the project and commented on earlier drafts of the study: Lisa DeMarco, David Morton, Bryne Purchase and Doug Stout. They would also like to express their gratitude to Positive Energy Project Coordinator Dr. Patricia Larkin for her exceptional skills shepherding the project to completion, and to the case study authors for their generous commitment of time, energy and insight to the study. As is customary, any errors of fact or interpretation remain the sole responsibility of the authors.

This study was originally commissioned by the Canadian Gas Association and Electricity Canada, with financial support from Natural Resources Canada. It has been revised and updated for publication by Positive Energy. Positive Energy would like to thank the CGA and EC for their agreement that the researchers could update and republish the study.

Positive Energy financial supporters:

We would like to thank the following organizations for their financial support:

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British Columbia Energy Regulator

British Columbia Utilities Commission

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Executive summary

The challenge of net zero is unprecedented – in scale, in complexity, in speed. Unlike previous energy transformations, it must be brought about primarily by public policymakers. Individual economic actors such as investors, utilities or technology developers – and in some cases consumers – have become active participants in responding to the challenge. But their ability to act and their confidence to invest depends in large measure on policy and regulation. Citizens have expressed support in principle for the goal of net zero but they have little understanding of what that means in practice and, when push comes to shove, will always give priority to costs and to the functionality (or as we have put it, the integrity) of their energy systems. If policy and regulation fail to deliver those results, no emissions reduction plan can survive, nor, in all likelihood, will any democratic government that tries to implement such a plan.

Against this backdrop, this study examines how various international jurisdictions have addressed these challenges with specific reference to downstream electricity and natural gas energy delivery systems. These systems comprise the physical energy infrastructure and business entities that build and operate gas and power systems and the policy and regulatory frameworks that govern those operations. The study examines what Canada might learn from other jurisdictions' experiences, and how these insights can inform policy, legislative and regulatory reform underway in the country.

Three cases were undertaken by experts on the ground in Great Britain, New York State and Western Australia. Drawing on relevant literature and interviews with senior leaders, each case presents the background and current context for emissions reductions policies; the evolution of energy policy reform; observations for key legislative, policy and regulatory reform processes; and lessons learned. This report's insights and recommendations for Canada also draw on Positive Energy research and engagement findings to date, in particular, studies on regulatory innovation and on regulatory independence and effectiveness. While the scope of this latter work extended to energy systems as a whole, many of the ideas and insights that emerged from it are relevant to downstream energy delivery in electricity and gas markets.

The study reveals that we are very early on this path and no jurisdiction has got it all figured out. Crucially, it is too early in the implementation phase to say whether any approach will prove to be effective in the long term. That said, it is becoming increasingly apparent that a number of basic principles should underpin efforts to achieve net zero. As noted, for the purposes of this report the focus is on energy delivery systems for power and natural gas, but the principles have broader application. In a sense, the principles seem obvious, but we see only limited instances of them informing government decision-making in Canada. In fact, often quite the reverse. That said, international cases as well as broader Positive Energy research reveal encouraging but tentative examples on which to build as well as pitfalls to avoid. For Canadian policymakers wishing to get Canada in good order to pursue its goals in 2050, all of these principles need to become central to policy thinking and action; without them, all the good intentions of governments, investors, consumers and citizens will come to very little.

The following principles should underpin government efforts to achieve net zero:

- There is a pressing need for well-articulated and coordinated high level policy – expressed through collaborative processes of ongoing planning and aimed at results that are durable and effective *even at the sacrifice of speed in the short term*.
- The 2050 goal will require high levels of active and ongoing cooperation among all relevant governments – federal, provincial, territorial, Indigenous and municipal – as well as coordination among all relevant policy and regulatory agencies within different governments (climate, energy, finance, innovation, infrastructure).
- Energy systems are just that, complex adaptive *systems*, and policy must be built on that understanding. It is vital that there be full integration of all energy system requirements – system integrity, affordability, emissions management and social acceptability – into decision processes from beginning to end.
- There is a vital need to expose consumers and citizens to the realities of energy transformation: costs and risks as well as opportunities and benefits. Clear answers to the questions surrounding who pays what, when and how for net zero are pivotal.
- It will be essential to place most individual project approvals or detailed policy and regulatory decisions in the hands of experts with close to the ground understanding – in other words, in many cases, relatively independent regulators operating with due process and within the context of clear policy guidance.
- The focus should be on results – constantly reducing emissions while sustaining well functioning energy systems. This implies, among other things, openness to as yet unknown technological possibilities and avoidance of technological determinism.
- Durable public support for energy system transformation will need to rest on open, inclusive, transparent policy, planning and approval processes, engaging communities and citizens, from beginning to end.
- Policy and regulation need to encourage innovation in technologies, business models, management systems and regulatory systems, most often through incremental experimental approaches combined with an intense focus on mutual learning across jurisdictions and agencies within jurisdictions.

None of this is rocket science. It is, in fact, much more complex than rocket science because it rests primarily on the untidy and unpredictable behaviour of individual humans and their governance and business systems. Much will not go as planned, there will be mistakes, and the goal of 2050 may prove elusive. But decisive and durable moves toward much lower emissions are possible – and that is the point. On the paths leading there, policymakers will be called upon to act in ways that have virtually no precedent; policy business as usual is not an option if net zero by 2050 is to be considered even a possibility.

With that in mind, in the last section of this report we offer a number of recommendations for Canada to move electricity and natural gas energy delivery systems toward the goal of net zero. The approach we envision is grounded in a collaborative process of mutual learning and action on delivery system reform convening federal, provincial and territorial policymakers and regulators alongside Indigenous and municipal governments and organizations, industry, civil society and academic leaders from the electricity and natural gas sectors. Crucially, the process would not supplant existing jurisdictional efforts towards emissions reductions, but rather, serve to reinforce, better coordinate and strengthen them. Key to the approach is respect for constitutional divisions of authority and the diversity of energy profiles and market systems across the country. Also key to the process is that it be, and be seen to be, collaborative, credible, influential and representative of the expertise and variety of organizations and perspectives required to successfully transform energy delivery systems in line with net zero. If done well, such a process would provide policymakers and regulators with many of the means by which to operationalize the above noted principles.

1 Introduction

In the face of challenges respecting both the substance and processes of regulation, most energy regulatory systems[1] have steadily adapted. But as pressures for change have grown – particularly in the context of the goal to reach net zero emissions by 2050 – the capacity of systems to adapt may not keep pace. Moreover, in the case of regulated or partly regulated natural gas and electricity utilities and energy service providers, despite delivering over half of the energy Canadians use, these organizations have to date been given little attention in the climate change debate, and still less has been given to the policy and planning that will be essential to reforming power and gas delivery systems for net zero.

Against this backdrop, this study examines how various international jurisdictions have addressed these challenges, what Canada might learn from them, and how these insights can inform processes of legislative, policy and regulatory reform across the country.[2]

The central question considered in this study concerns the *delivery of natural gas and electricity in end use markets in a way that responds to climate goals (net zero) while maintaining the integrity of delivery systems and assuring energy affordability and – ultimately – political sustainability of emissions reductions policies*. In this report, system integrity refers to the collection of attributes that make the system operational, that is, safety, security, reliability, and resilience.

This report presents the findings of case study research on energy policy and regulatory developments in three international jurisdictions. The research aimed to identify key insights for Canada in its regulation of energy delivery system players on the road to net zero. Using a common template, the cases were undertaken by experts on the ground in Great Britain (GB), New York State (NY), and Western Australia (WA). Drawing on relevant literature and interviews with senior representatives of utilities, regulators, legislators, policymakers, energy economists, and other experts, each case presents the background and current context for emissions reductions policies; the evolution of energy policy reform in the jurisdiction; observations for key legislative, policy and regulatory change processes; and lessons learned. The case studies are summarized in Section 3 and the full cases are found at the end of this report.

This report also draws on insights gained through pan-Canadian research and engagement on energy policy and regulation that Positive Energy has spearheaded since 2015 (see the box on the following page for more information about Positive Energy). This has included numerous studies of energy regulation, direct involvement in the annual Energy and Mines Ministers Conference, research collaborations with multiple organizations including CAMPUT (Canada's Energy and Utility Regulators) and close work with an advisory council of energy and environmental leaders from across the country.

The report is structured as follows:

Section 2, *Challenges and tensions across different jurisdictional contexts*, sets up a general frame or backdrop against which to read the report.

Section 3, *Case studies in brief*, provides a brief overview of each case, highlighting key findings for each jurisdiction.

Section 4, *Key insights and themes emerging from the case studies*, provides a synthesis of the case study findings that we believe have the largest consequence for policy and regulation in Canada. This includes early lessons of what works and what doesn't, as well as promising practices to consider.

Section 5, *Insights and recommendations for Canada*, builds on what can be learned from the three cases and incorporates insights from broader research and engagement at Positive Energy. Several aspects of Canada's particular context are highlighted at the outset of this section. These will fundamentally shape the possible processes Canadian jurisdictions might take to reforming energy delivery regulation in the years ahead. Section 5 also proposes a roadmap for mutual learning and action for Canada, including key action items and deliverables for utility regulatory reform, along with suggested roles and responsibilities for various players.

1 We include both regulators and the overarching legislative and policy frameworks within which they work.

2 This study was originally commissioned by the Canadian Gas Association and Electricity Canada, with financial support from Natural Resources Canada. It has been revised and updated for republication by Positive Energy. Positive Energy would like to thank the CGA and EC for their agreement that the researchers could update and republish the study.

About Positive Energy

The University of Ottawa's Positive Energy program uses the convening power of the university to bring together academic researchers and senior decision-makers from industry, government, Indigenous organizations, and civil society to determine how to strengthen public confidence in energy and climate decision-making. Positive Energy's work has proceeded in three phases:

Phase I (2015-2018): Public confidence in energy decision-making

Phase II (2018-2022): Canada's energy future in an age of climate change

Phase III (2022-2027): Public confidence on the road to net zero

In the current phase on net zero, Positive Energy's research and engagement focus on helping Canada move from the 'what' to the 'how' of emissions reductions, with a primary emphasis on developing integrated approaches to energy and climate, identifying institutional innovations that support durable change, and fostering cross-country collaboration. Activities of this phase focus on the following areas:

- **Regulation:** how to develop effective and trusted regulatory frameworks to achieve energy and climate objectives.
- **Energy Security:** how to ensure domestic and global energy security (affordability, reliability, availability) alongside emissions reductions.
- **Intergovernmental Collaboration:** how to foster effective intergovernmental relations among federal, provincial, territorial, Indigenous and municipal governments to achieve energy and climate objectives.
- **Public Opinion:** how to foster ongoing public and expert support for Canada's net zero journey.

For more information, please visit the Positive Energy website.

2 Challenges and tensions across different jurisdictional contexts

This section sets up a general frame or backdrop against which to read the report and the cases.

To begin with, the policy problem facing all jurisdictions can be stated as follows:

> The central question concerns the *delivery of electricity and natural gas in end use markets* in a way that responds to climate goals (net zero) while maintaining the integrity of the delivery systems and assuring energy affordability and – ultimately – political sustainability of emissions reductions policies.

Throughout the report we refer to the collection of attributes that make the system operational (safety, security, reliability, resilience) as "system integrity".

Behind this statement lie several dimensions of which we believe three are the most important to bear in mind.

2.1 Common challenges

The challenges across jurisdictions are roughly similar – how to fundamentally transform one of the most critical parts of societal and economic infrastructure with unprecedented speed, and in a way that ensures coordination between policy and regulation, among different levels of government, and among the various public, private and civil society organizations involved in natural gas and electricity delivery. To that extent comparisons are potentially fruitful.

Roughly speaking, we might describe the challenges in terms of the physical and organizational changes that need to be made to natural gas and electricity systems, what are often referred to as "pathways". Different jurisdictions are contemplating or confronting some mix of all of the challenges below. Crucially, we are just beginning these processes and it is too early to say with certainty whether any jurisdiction's approach will prove to be effective in the long term.

- How to accommodate the potentially massive growth in electric system load and changes in load profiles entailed by electrification, including calls from some to electrify almost all energy use. Flowing from that, how to manage all the issues surrounding new infrastructure and system management.
- How to integrate new sources into power systems including renewables, storage, distributed energy and demand side response in ways that sustain the integrity of the systems.
- How to support emissions reductions in natural gas systems, including the ongoing greening of the gas delivery system through energy efficiency and demand side management and the introduction of low GHG alternatives from renewable natural gas (RNG) to hydrogen.
- How to address natural gas systems potentially becoming obsolete if they are replaced by an all-electric system and all that implies for system integrity, stranded assets, stranded customers and cost allocation.
- How to integrate planning for and optimize power, fuel and heat systems (combining gas, hydrogen, electricity, heat and local renewables in integrated systems).
- How to transform the respective roles and business models for utilities, energy service providers and technology providers and create investment conditions that make the new systems work.
- How to account for inevitable supply constraints respecting critical materials, skills and workers in the economy writ large and within public authorities.
- How to reconcile the local character of the problem with the realities of distant energy sources and interconnected systems at a regional scale.

2.2 Different contexts

The context varies widely among jurisdictions. Particular conditions in each case influence balance, speed and priorities and in many instances are the crucial variables governing the process and potential for change. Any effort to adopt models from other jurisdictions should be undertaken with this in mind.

Several aspects of context are relevant:

- The most obvious is physical. Decision-makers have to ask: What energy sources are available? Do they come from within the jurisdiction and if not, what implications does that raise for cross-jurisdiction cooperation or conflict? What are the available delivery routes? What are the drivers of load on the system (e.g., space heat or cooling, seasonal variability, industrial, resource sector or commercial demand)?
- Constitutional and legal factors can facilitate or constrain – most notably the effects of federal versus unitary systems and, distinctively for Canada, the imperative of accounting for the rights and roles of Indigenous peoples.
- Political cultures differ, among them the extent to which societies might be amenable to central economic direction, and expectations among the populace with respect to the ability to directly shape policy and that policy and regulatory processes be open and inclusive.
- Governmental machinery and associated practices can vary regarding the respective roles of legislative bodies and the political executive and the degree to which authority is devolved to independent bodies from planning commissions to regulators. Public ownership in the energy delivery space and the influence of Crown corporations on policy development is also a crucial element of context, particularly in Canada.

2.3 Universal tensions

The tensions that underlie the challenges are broadly similar across jurisdictions: people being people, investors being investors, governments being governments and regulators being regulators. Again, this makes comparison potentially fruitful.

- At its most basic, the tension behind the drive to net zero is how actions that deliver very little direct or immediate energy benefit to citizens can be undertaken while sustaining citizen support for climate action.
- The most critical threat to that support is common across all jurisdictions: how to reduce emissions while sustaining the two foundational imperatives of any energy system – system integrity (does it work?) and affordability (can we pay for it, who pays for what, how and when?). What are the respective roles of policymakers and regulators, and how can governments best pursue environmental objectives alongside economic regulation?
- How to secure community and investor support for new energy infrastructure. Local acceptability and the investment environment are intertwined unavoidable factors that govern whether new facilities can be approved and built and that shape the speed and costs of doing so. People want energy services but they do not necessarily support the construction and operation of the physical facilities needed to deliver those services. And when the benefits of the services and the costs of facilities are unevenly distributed – for example as between urban load centres and rural communities where energy facilities are built – the tension can become acute and erode political support – and investor support – for emissions reductions.
- In process terms, several tensions manifest themselves. Net zero requires speed, predictability for investors and supportable costs. Citizen support requires openness, engagement and due process, which adds time, reduces predictability and almost always adds costs. How can governments best navigate these tensions?

3 Case studies in brief

The case study research focused on the subnational level: Great Britain (GB) (the jurisdiction of the United Kingdom that includes England, Scotland, and Wales); New York State (NY), and Western Australia (WA). The following briefs take a historical approach, with key points of interest highlighted in bold. The full case studies are found in the Appendix.

3.1 Great Britain

A government decarbonization policy for the GB energy market began in 2000. By 2019, GHG emissions had fallen by 44% from 1990 levels, and in 2020 GB produced more electricity from renewable sources than from fossil fuels for the first time.[3] However, in 2021, more electricity was generated by fossil fuels because the conditions for renewables were less favourable (less wind). The overall progress for renewables has been primarily supported by incentive schemes for new renewable generation designed to deliver stable cashflows to attract investors.

In 2019, the government passed legislation to reach net zero carbon emissions by 2050, with current policy for a net zero electricity system by 2035, subject to security of supply.[4] A three-pronged policy approach that is officially over but continues to be supported by the market, includes: 'decarbonization', with subsidies for renewable generation, heating, and carbon taxes; 'affordability', with a cap on retail energy prices, network operators expected to work at the lowest reasonable cost and discounts payable to vulnerable consumers; and 'security of supply' in the form of a capacity market designed to be technology neutral.

Formed in 1999, the Office of Gas and Electricity Markets (Ofgem) is the independent national regulator for gas and electricity market generators, network operators, and suppliers. Ofgem's principal objectives in protecting the interests of existing and future consumers are to reduce gas and electricity supply GHG emissions while maintaining security of a diverse and viable long-term energy supply. Wherever appropriate, Ofgem aims to promote effective competition. In decision-making, Ofgem has regard to such issues as: contributing to the achievement of sustainable development, promoting efficiency, and addressing the interests of vulnerable consumers (with a recognition that changes may be easier or more advantageous for some people).

There is no state ownership of energy assets. Natural gas and electricity industries are self-governing based on a set of codes, an approach that has not been adopted in any other market. In electricity, the penetration of renewable generation is large. Currently, almost every form of generation in the GB market is entitled to some form of subsidy. The amount of intermittent generation has reached a level where both the practical challenges and costs have become significant. At the same time, there is a common perception that heating will be electrified, concurrent with the aforementioned net zero electricity policy.

With respect to gas, ongoing debate concerns whether this fuel will remain important, either as methane blended with biogases (or RNG) or hydrogen, or with carbon capture and storage (CCS). Moreover, should unabated gas generation be phased out in the 2030s, again as per the above noted net zero electricity policy, the operator of the high voltage electricity transmission system suggested it could become more challenging to maintain electric system security of supply.

Regarding gas and electricity transmission and distribution, networks operate as monopolies and a key concern is that the design and operation of electricity networks need to evolve. An Ofgem focus on short-term cost optimization reduces incentives for transmission investment, meaning the output of renewable generation is often constrained, leaving consumers paying twice: once to subsidize construction, and then to curtail output. This focus on short-term cost optimization arises from Ofgem's interpretation of its mandate, some say an interpretation that lacks accountability. Suppliers, as the third group in the value chain, are also privately owned, and sell to end consumers in a fully competitive market. To deliver net zero, new supplier business models will need to emerge to support consumers, for example, through energy-as-a-service propositions.

3 2020 was heavily impacted by COVID-19; 2021 data is available at https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes.

4 This caveat, some believe, means that the target may be missed.

Britain is now at a key point in its energy transition. Notably, the British experience shows it is relatively straightforward to deliver a sizeable degree of decarbonization in the electricity market, but that the challenges around low-carbon gas are significantly larger. But it also shows that there are limits to what a renewables-driven transition can achieve unless actions to mitigate intermittency are developed at the same pace.

Ofgem has been in the spotlight. It issued its first decarbonization plan in 2020 and the House of Lords Industry and Regulators Committee initiated an inquiry, Ofgem and net zero, shortly thereafter. The 2022 Government response to the report confirmed the regulator's role in the energy transition, suggesting Ofgem's existing objectives and powers were in keeping with achieving net zero. Further, in their report on "Energy pricing and the future of the energy market" inquiry, the Department of Business, Energy, and Industrial Strategy (BEIS), responsible for energy and climate, was highly critical of Ofgem's regulation of the retail energy market, in part because of a large number of supplier failures. Wide ranging recommendations for Ofgem's regulatory oversight, accountability, and transparency were proposed. Lastly, BEIS and Ofgem are jointly consulting on proposals for an expert impartial Future System Operator (FSO) with responsibilities across both the electricity and gas systems, to drive progress towards net zero while maintaining energy security and minimizing costs for consumers.

It has been suggested that Britain's highly centralized system could be an asset in the transition to net zero, allowing changes to be made at the national rather than regional level. Arguments support a centrally planned approach that could deliver faster results. But there are concerns across the industry that without reform to the way in which networks are operated and paid for, and the mechanics of wholesale market price formation, these investments will fail to deliver the desired results, and the enabling investments in storage and demand-side flexibility will fail to emerge at the necessary scale. Others question whether markets and competition can deliver the necessary solutions in the mandated timeframe.

Furthermore, the costs of decarbonization, which are borne by end consumers through their electricity bills, are high and rising, creating significant political pressure for action on high energy prices for households and for energy intensive industries. Cost support schemes, funded through industry taxation and government borrowing, are announced regularly. These coincide with growing debates about the public's appetite for both the costs of achieving net zero and the lifestyle changes necessary.

A successful transition to net zero will only be achieved with the active agreement and co-operation of voters. Indeed, there has been a significant drop in the number of people considering climate change to be a key issue. Between March 2022 and March 2023, the issue dropped from 16% to 10% of top mentions in public opinion research. Post-pandemic GB issues include inflation/prices, the economy, and the post-Brexit world. Other energy-related concerns include the potential lack of deployment in any meaningful way for both demand reduction through improved thermal efficiency, and deployment of aforementioned technologies that are assumed to be necessary to achieve net zero, such as hydrogen and CCS.

3.2 New York

Energy efficiency efforts for both electricity and natural gas began in earnest in New York State in the 2000s.[5] From 2010-2019, NY eliminated its reliance on coal generation; continued to rely heavily on natural gas, nuclear, and hydroelectric generation; and saw a 50% increase in reliance on renewable resources. NY currently uses less energy per capita than any other state. Today, key energy policy objectives include achievement of statutory requirements for reductions in greenhouse gas emissions, resiliency[6] and environmental justice,[7] alongside longstanding concerns for reliability, affordability, and safety.

5 Prior to that time, utility energy efficiency programs were very small.
6 Hurricane disasters in the 2010s served as a reminder that "resilience" of energy infrastructure is an important policy objective and distinct from oversight of "reliability".
7 Environmental justice in the NY context refers to communities, and in particular, "disadvantaged communities", having the opportunity to participate in decisions that may affect their environment or health. While targets have been established, measurement criteria have not been finalized.

Historically, and to a greater extent over the past decade, energy policymaking has been dominated by the governor's office, including an unusual degree of oversight of the regulator, the Public Service Commission (PSC), through input and feedback on PSC staff technical and policy white papers and PSC orders. The PSC has therefore had multiple roles as policymaker, policy implementer, utility auditor, and rate setter. Additionally, the NY Energy Research and Development Authority (NYSERDA) role as a policymaker and market participant has grown, particularly as it relates to securing large scale renewables and influencing the development of transmission necessary to move wind energy from both offshore Long Island and upstate NY to NYC.

The 2014 PSC restructuring model (Reforming the Energy Vision or REV) focused on electricity, with an emphasis on integrating distributed energy resources, enabling markets, and promoting innovation. Utilities were successful in influencing policy at the PSC while at the same time being required to work collaboratively through demonstration projects and fulfilling the PSC request to file joint comments in all REV and related proceedings.

The sense of urgency to decarbonize the economy has increased substantially with the enactment of the *Climate Leadership and Community Protection Act* (CLCPA) in 2019. In addition to codifying the net zero targets in statute, the CLCPA created a Climate Action Council (CAC) that developed a Scoping Plan to meet the requirements, publishing their final report in December 2022. Working in parallel, a Climate Justice Working Group defined and applied criteria to classify certain communities as "Disadvantaged Communities," directing that at least 35% of spending on energy efficiency and clean energy be directed to these communities.

The 2022 CAC Scoping Plan provides guidance for decarbonization of all sectors of the New York economy including the utility and transportation sectors. It observes that every sector will require a substantial transformation and concludes that the 2050 targets can be met. Energy efficiency and extensive electrification of all end uses are required. The Scoping Plan assigns numerous implementation responsibilities to the PSC and NYSERDA and additional legislation is likely. NY's approach to energy policy is therefore evolving from a focus on promoting clean energy when economically efficient to a "planning-centric" model that is rationalized based on the need to comply with the CLCPA and achieve mandated targets. While the CLCPA did not establish targets by sector or for natural gas utilities within the gas utility sector, the impact of the CLCPA on gas is rooted in the requirement for net zero emissions from the electricity sector by 2040. This is significant because natural gas is the primary fuel for electricity generation.

According to the Plan, the transformation of the electricity sector away from natural gas incorporates a reliance on large scale renewables, modernization of the electric grid, and investments in storage and other dispatchable energy technologies. A second piece of legislation, the *Accelerated Renewable Energy Growth and Community Benefit Act* (2020) is intended to help with the buildout of the electric system by requiring investment in electricity transmission and distribution capacity. Under the Act, the PSC is required to work with the NY Independent System Operator (NYISO) and electric utilities to identify bulk and local transmission upgrades and distribution network upgrades necessary to connect and deliver large-scale renewables from renewable energy projects (including offshore wind) to in-state markets.

The Scoping Plan calls for a "strategic downsizing of the gas system" and coordination of the transition between the electricity and natural gas sectors. Utilities are required to develop long-term gas plans on a staggered schedule that consider the implications of electrification on gas operations over the next 20 years. The individual gas utility long-term gas plans and planned statewide gas pathways study, and upcoming rate case decisions, will test the validity of the path as they reveal the trade-offs between reduced reliance on natural gas for building heating and cooling (and associated declines in throughput) and the impacts on utility rates and other costs.

The focus on clean energy highlights the potential conflicts between New York's ambitions and the goal of maintaining affordable and reliable energy supply. Although achieving the CLCPA's goals depends critically on actions to be taken by utilities under the direction and oversight of the PSC, in contrast to earlier influence, the ability of the utilities to influence the CAC's draft scoping plan was limited. Currently, utilities generally remain on the defensive regarding the role they can serve and their ability to be fairly compensated for the risks they are asked to absorb in CLCPA implementation. There are clear indications that this issue will become increasingly fraught with engagement from environmental organizations and other stakeholders in the end-to-end planning process including scrutiny of forecasts, debates over planning methodologies and modeling assumptions, and litigation of proposed investment decisions.

Moreover, final decisions are now subject to appeal if parties can make a case that provisions of orders are inconsistent with the CLCPA. This is important because of an expressed concern by regulatory experts that a number of elements in the Scoping Plan are unrealistic and/or infeasible from a regulatory and customer viewpoint.

Ultimately, the New York Public Service Commission (PSC) oversees investments, new programs, and cost recovery associated with decarbonization actions taken by electric and gas utilities. Utility long-term decarbonization plans and cost recovery cases will require the PSC (and commissions elsewhere) to wrestle with whether it is possible and how much it might cost to achieve the targets within the prescribed timeframes. Achieving the targets at reasonable costs will depend on new technologies (e.g., production of hydrogen), efficiency improvements in emerging technologies (e.g., heat pumps), and the ability to develop, interconnect, and transmit large-scale renewable generation.

Finally, there continue to be issues of transparency. A collaborative approach, where all stakeholders have an opportunity to engage earlier in the decision-making process, would be beneficial. While the enabling investments and utility decarbonization programs to achieve the targets – as well as the rates to be paid by customers – are approved by the PSC in periodic rate cases filed by electric and gas utilities, the quasi-judicial hearings are sometimes difficult for wide-ranging stakeholder participation. Moreover, the amount of discretion the PSC will have for decisions to support the CLCPA and Scoping Plan is unclear.

3.3 Western Australia

As a subnational jurisdiction, Western Australian energy and climate policy is increasingly driven by Canberra as decision-making shifts to the federal level. This federal involvement in electricity and gas (and more recently climate policy) stems from the goals to create a national energy market, enhance interconnection of state grids, and, more recently, with the election of the Australian Labor Party in May 2022, a renewed emphasis to address climate change.

Both Australia and Western Australia have established a goal for net zero greenhouse gas emissions by 2050. Australia enacted the *Climate Change Act* (2022) that sets the federal emissions reduction target at 43 percent below 2005 levels by 2030; and Western Australia is expected to pass state legislation in 2023 to formalise the aim to reduce government emissions by 80 percent below 2020 levels by 2030.[8] In addition, Australia has enacted the *Safeguard Mechanism (Crediting) Amendment Act* (2023) that provides for a reduction of emissions from large industrial facilities (over 100,000 tonnes of emissions per year) with a 'hard cap on pollution'.

These legislative and policy changes have occurred against the backdrop of much more localised energy systems and decision-making. Australian states have been the traditional regulators and owners of energy assets. In the case of WA, electricity and gas grids are physically islanded from the larger national energy market. Since 2021, two key trends in the WA energy sector are a shift away from privatization and deregulation, alongside a coordinated effort to address the implications of decarbonization. While electricity is predominantly public and gas is predominantly private, the two are interlinked. As the system evolves, it is quite possible that the two will become more integrated.

With respect to electricity, integrated Crown utilities dominate generation and distribution networks. While the Economic Regulatory Authority (ERA) approves the network access, the energy minister can exercise significant influence given that retail prices are set by government and the utilities are also owned by government. Liabilities (relating to the difference between retail prices and costs of production) and responsibility for keeping the lights on therefore rests with the government.

A high penetration of residential solar renewable generation began to materially impact the grid through the 2010s. By 2019 there was the realisation that a business-as-usual approach to responding to the ongoing energy transformation would result in system and market failure, as well as concern for the overall viability of the energy sector. Three key 2019-2021 initiatives include: the Standing Committee of the Legislative Assembly Inquiry, Taking Charge: Western Australia's Transition to a Distributed Energy Future; establishment of Energy Policy WA, an organization aimed at improving and centralizing policy expertise; and a time limited Energy Transformation Taskforce that completed work streams focused on distributed energy resources (DER), Whole of System Planning, and Foundation Regulatory Frameworks.

8 Should this extend beyond state-owned assets, it may cause significant political challenges.

Turning to natural gas, it would be difficult to overstate its role and importance to the WA economy. The state has significant domestic production, extensive use of gas in the electricity sector, and active plans to introduce renewable hydrogen into the gas network. Reforms and privatization of the gas sector prior to the 2000s resulted in limited direct government involvement. Unlike electricity, gas is viewed primarily as an export commodity under the Department of Jobs, Tourism, Science and Innovation (JTSI). JTSI is an economic development and international trade agency.

While large LNG investment decisions are slated for the short term, as part of efforts to reframe energy and infrastructure debates after the COVID-19 shock, public commentary on the role of natural gas in the economic recovery was not met with universal acceptance, although by positioning it as growth of blue-collar jobs and regions made it politically challenging to reject outright. Now, with the new safeguard mechanism and hard cap on emissions, the LNG industry is facing further headwinds.

Another issue facing the natural gas sector has been the ambition to export green hydrogen and the impact that this will have on domestic systems. The gas industry has had to respond to bi-partisan ambitions for WA to become a green hydrogen 'superpower'. With just two demonstration plants, touted by some as a public relations exercise, the larger prize will be to facilitate exports given the relatively small domestic market. Technical, regulatory, and legislative reforms are underway. Nevertheless, there appears to be a greater realization that the hydrogen sector will not replace the LNG sector and that private investors will still need an appropriate rate of return.

In the broader electricity sector, where there is still a large degree of uncertainty and increasing reference to sovereign risk, it is anticipated that much of the energy transition will likely be funded by governments and ultimately taxpayers.

Energy Policy WA appears to have taken on many of the policy functions that existed within the previously integrated crown utility. Energy Policy WA is engaging with consumers and consumer interest groups. It is tasked with broader market development functions for the Wholesale Electricity Market and Gas Service Information arrangements, the ongoing development of Whole of System Plans for the South West Interconnected System, and functions of the former Rule Change Panel. Layered consultations have been recommended. For DER, as an example, there are plans to organize a public forum and an invite-only gathering to develop a list of actionable tasks.

The cumulative impact of federal government interventions has slowed investment. Some analysts point to an acceleration of the offshoring of trade-exposed, emissions intensive industry (de-industrialisation). Additional WA energy concerns include: a key shortcoming of the Taskforce's Whole of System Planning workstream, where there was a separation of energy and carbon market discussions, with carbon pricing not formally included; addressing barriers to stand-alone power systems, with 3 percent of users using 52 percent of the network services; closing coal, especially the Collie region (a public announcement that could not have been delayed any longer); and equity concerns regarding the impact of energy costs on poorer households. At present, there have not been any substantive calls for a 'just transition', which radically redefines subsidization with the energy system as a welfare mechanism.

Overall, incremental reform of the energy system is seen to be the optimal approach. Transformation would be coordinated by Energy Policy WA, with any necessary changes funded and managed directly by government and crown utilities. The recentralization of the technical and policy aspects of the energy sector was not implemented to 'punish' the regulator. Indeed, the ERA had performed its function as per the relevant act and provided a robust process to review proposed access arrangements (a large component of electricity costs). Going forward, pressure on the regulator is likely to increase as governments expect a wider interpretation of existing legislation. The optimal solution would be for the government to lead a bipartisan effort to reform the function, role, and duties of the regulator to respond to the fast-changing energy sector.

While there is overall, bipartisan agreement on the importance of climate change, the overriding desire of elected officials, their advisors and senior bureaucrats, well above ideology, is 'keeping the lights on' and avoiding household pain with electricity bills. No reform will progress if it fails these tests.

4 Key insights and themes emerging from the case studies

This section is a synthesis of the primary themes emerging from the case studies. It does not claim to be exhaustive but, rather, focuses on the findings that we believe have the largest consequences for policy and regulation and that are most germane for Canada as we look to achieve net zero GHG emissions by 2050. It bears underscoring that the case jurisdictions are all in the process of developing and implementing policy and regulatory changes to dramatically reduce emissions. In most instances, it is too early to evaluate success or failure definitively, but it is possible to distil promising practices and dangerous pitfalls.

The insights and themes are organized under seven headings. The first two are essentially contextual and comprise the broad surrounding economic, social, environmental and physical realties. The next four concern matters under the direct control of policymakers, from the establishment of objectives through to the tools available to governments, to the roles of various governments, to how governments can go about reforms. The last theme concerns consequences: what appears to work and what does not.

While the observations that follow are rooted in all the case studies, in several instances we refer to specific cases under the rubrics GB (Great Britain), NY (New York) and WA (Western Australia).

4.1 Challenges, opportunities, and costs in market-based systems – and the alternative of centralized control

Market-based energy systems (with economic regulation limited mainly to natural monopolies) have become the norm in most jurisdictions over the past 20 to 30 years, starting with natural gas and later encompassing electricity. The overarching question for our purposes concerns how market participants (suppliers, pipes and wires, users) respond to market or regulatory signals and how that affects emission strategies and durability of reforms.

Two of the cases in particular (GB and NY) underscore how unbundling of energy service delivery, privatization of energy delivery and market pricing may be hard to reconcile with effective and rapid decarbonization. With multiple players in complex systems, behaviour and outcomes are hard to predict, far less control – all the more so in the face of a policy-driven transformation of unprecedented scale, nature and speed. What remains far from clear, is whether more centralized and dirigiste methods in a democratic context can possibly cope with the demands of the transformation.

An important question concerns whether what was learned from the market transformations of the past several decades (privatization, unbundling, deregulation, restructuring) has relevance for the net zero transformation. On its face the answer would appear to be very little since policy is now being driven by a new non-economic imperative (climate) that pulls decision-makers in the direction of more government intervention – not less. On the other hand, much has been learned about consumers, including their general preference for being relatively passive players concerned mainly with knowing that their systems work and being intolerant of price shocks.

Achieving the desired net zero outcome depends fundamentally on the system and its participants being creative, innovative, nimble and adaptable. Much of the technology that will need to be deployed is at best untried at scale, at worst, unknown. New market structures, corporate structures and business models, and new approaches to policy and regulation will need to emerge and evolve. It is impossible to know conclusively what factors will bear on all of this and how they will interact.

Several issues illustrate the complexity and the political, economic and social perils.

Precipitate action by policymakers applying the technologies and business models we know today (and in the GB case, a highly complex mix of regulations and incentive systems) risks locking in sub-optimal approaches that will leave legacies that could take decades to resolve.

Cost effects will impinge on consumers, whose willingness or ability to absorb such costs has been consistently demonstrated to be very limited – and when limits are reached the political blowback is almost always impossible for policymakers to escape.

The costs of change inevitably bear disproportionately on disadvantaged consumers, a societal outcome widely regarded as unacceptable in twenty-first century democracies.

Effects on safety, security, reliability and resilience (what we term "system integrity") are often unpredictable and subject to both internal and external factors. To date, requirements for system integrity have generally been met, in all probability for three reasons: because the systems were designed with system integrity as the first priority; because the physical systems themselves have long been generally stable and well understood; and because recent changes (electrification, distributed energy resources or DER, integration of renewables, etc.) have been mostly at the margins of the system. None of those conditions appears to apply as we look to the coming transformation to net zero. Electricity grids in particular could reach a tipping point, as appears to be the case in GB. Failure to meet the requirements of system integrity could be catastrophic societally, economically and politically.

4.2 Physical pathways: avoiding one size fits all

The three cases illustrate how physical conditions vary from place to place and thereby affect both opportunities and challenges.

The inherent inertia of legacy systems built on long-lived capital, readily available but carbon intensive resources and long-established human skills and management systems – and the need for new skills, sufficient workers and management systems – are mismatched with the speed of change envisioned by net zero. The availability of low or zero carbon resources varies widely depending on climate conditions, geography and social acceptability; there is no model that fits all conditions. Correspondingly, the potential responsiveness at the demand end varies depending on industrial profiles, climate, the nature and age of energy using assets and the potential for distributed energy to be practically deployed.

The basic physics of power and natural gas systems impinges unavoidably on the potential for change. Heat requirements – especially for certain industries – affect what is practical in choice of supply. The requirement for real-time load balancing in power systems is a physical fact and as intermittent renewable resources become more dominant the practical consequences for system design and real-time management become ever more challenging. The materials and land intensity of renewable systems raise whole new perspectives on security of supply, resilience and social acceptability.

Local renewable sources may in and of themselves be more economic than distant sources due to reduced transmission requirements, but that may be in tension

with more cost-effective, reliable and resilient large scale renewable sources looked at from an overall system perspective.

The economics and operational practicality of existing systems are vulnerable to the effects of rapid change. Power systems from upstream to down are called on to accommodate growth of two (or more) times existing capacities, the need for new system management tools and accommodation to changing seasonal load profiles. Alternatively, declining utilization of existing natural gas systems potentially leaves stranded assets whose costs must be accounted for and potentially stranded users for whom new systems may be impractical or excessively costly. The advent of electric mobility adds load and system management complexities. Even with a whole system perspective on needed energy services – heat, cooling, mobility, drive power, lighting, electronics – there is no way from today's perspective to know what will actually work. Without at least some system perspective we are flying blind in the wind.

The effects of climate change itself are a physical fact whose consequences are unknown. What is highly probable is that such effects are going to grow and will dominate investment choices and thinking about supply, including the wisdom of developing energy systems that lack diversity and optionality.

Physical conditions also include people. Divergent urban and rural economies – a fact most striking in NY – produce not only different system demands but also willingness to accommodate the energy realities of distant communities. Demand response reacting to prices or positive incentives varies widely and unpredictably. And in a larger sense, "people" also includes geopolitical actors whose behaviours unavoidably impinge on questions of security and reliability, a question that has been old news since the end of the Cold War but has come charging back in the form of both materials security and security of supply effects of aggressive actors such as Russia.

4.3 Policy objectives and practical realities: bridging the disconnects

The idea of net zero emissions by mid-century has, over the past few years, become firmly embedded in the public discourse. In New York and Great Britain (but not Western Australia) that goal is now expressed in legislation, thereby creating an imperative for action that has been absent from most climate policy worldwide for the past several decades. Legislation can always be changed of course but politically the idea of net zero appears increasingly to be set in stone.

Not surprisingly but strikingly, the three cases reveal the extent to which countervailing realities, even if not set in legislative stone, remain economic and political bedrock.

Consumers of energy remain acutely sensitive to increasing energy costs. This was seen most recently in GB where several factors, some unrelated to climate policy, have generated a crisis due to rising costs. Government has acted to constrain or mask those costs, a tendency that is unlikely to be sustainable in the long term. In WA, most cost impacts have been kept hidden from consumers through use of taxpayer funded subsidies. In NY, where the net zero legislative mandate is relatively new, emissions remain the dominant political imperative despite growing concerns on the part of utilities that the costs of new systems have been given inadequate attention. Behind all of this lie the impacts on economically vulnerable consumers and on the competitiveness of energy intensive industries.

System integrity (safety, security, reliability, resilience) has largely been taken for granted with established energy systems but questions loom as we look to the radical transformation entailed by net zero. The effective integration of intermittent renewables presents growing concerns in GB. Consumers in WA expect above all else that their systems will be reliable. In NY, debate is growing as to the prudence of making the whole system dependent on electricity.

The critical questions for policymakers and regulators are twofold. First, whether they are paying adequate attention to these countervailing imperatives and anticipating potential crises in costs or system integrity and adjusting accordingly or whether they will find themselves facing unpleasant surprises for which they are unprepared. Second, whether it is prudent, even if politically compelling, to mask cost impacts if the effect is to blunt market signals or to simply pass costs on to future taxpayers, a strategy that may be fiscally unsustainable in the long term.

The technologies that will underpin net zero remain elusive. Many are known in principle but remain far from being feasible in widespread application. This fact runs hard into what may be the most profound policy question of all: whether markets and market actors can respond in a timely manner or whether the pace of change implied by net zero requires central planning that may be unprecedented in market economies except in wartime.

It seems clear that some measure of planning will be essential. NY and to some degree GB illustrate large scale, system wide planning efforts that have had both successes and failures. The drive for emissions reductions centred in the NY governor's office afforded a measure of policy, legislative and program coordination over time, but it is an open question whether NY has grappled sufficiently with economic imperatives and system integrity. In GB, arguably, the decarbonization of power supply has been a success, but that has come with costs, some of which are just now emerging – and the next phases of decarbonization will involve vastly greater complexities extending across the entire energy system.

In terms of processes of reform, in WA various mechanisms have been tried with some success, including the creation of time limited task forces aimed at framing a path forward, using legislative committees to mediate discussions and better inform political and bureaucratic actors, or bringing Treasury (finance) perspectives into the centre of the debate. But in none of the subject jurisdictions has anyone apparently solved the problem of how to create planning systems that do in fact move quickly; that can be nimble, innovative and adaptable; that allow multiple agencies and authorities to act in a coordinated manner and achieve the ever elusive “system thinking”; that solve simultaneously for environmental, economic and social imperatives; and that adequately encompass citizen demands for inclusion. In short, nobody has yet figured it out.

4.4 Regulatory effectiveness in a sea of policy instruments and other government institutions

The overarching question concerns who is in charge.

As noted earlier, an overriding theme arising notably in GB and NY is the question of whether markets and market actors can be sufficiently responsive to meet the compressed time frame of 2050 and sufficiently predictable to act in ways that make hard legislated mandates achievable. Against that, of course, is the mystery of whether central planning – even if it permits the executive to exercise control – can meet the multiple imperatives of nimbleness, adaptability and openness, all in the face of social, economic and technological unknowns that greatly outweigh what *is* known and the inevitable limitations of modeling and forecasting in the face of so many unknowns.

Characteristically, the traditional machinery governing electricity and natural gas delivery systems – essentially monopoly utilities for wires and pipes overseen by expert economic regulators – is slow to move and risk averse. In other words, aside from the conundrum around central planning versus markets, the actors who normally operationalize policy direction in the energy delivery system have deep knowledge of the system but are not particularly nimble (at least sometimes that is for good reason given constraints about assurance of safety and reliability as well as fairness and openness to input from multiple sources). In contrast, the political executive driven by the net zero imperative may be faster to move but often lacks sufficient expert capacity and may struggle to maintain system integrity, affordability, and, by extension political support for emissions reductions. It may also be inclined to create new legislation, policies, public entities and programs as new issues and problems arise, leading to an increasingly complex system that defies comprehension and clarity (GB).

This leaves an ongoing question concerning what role regulators should play in an increasingly crowded energy and climate decision-making system. If their expertise and capacity to ensure due process remain important, how best can the political executive provide them with the scope and the direction to take into account imperatives – notably emissions reductions imperatives – other than the traditional economic bedrock of fair and reasonable rates?

Should policymakers be more directly engaged in the leadership and governance of regulatory agencies (NY)? Alternatively, if policymakers are unable to provide clarity of direction, to what degree should regulators be creative in interpreting their mandates (WA) or explicit in how they will manage trade-offs (GB)? If regulators do that, how are such actions squared with the question of political accountability? In short, it is crucial to think through very carefully the transformation of economic regulators into economic/environmental regulators. Throwing the baby out with the bathwater is a risk (NY).

One striking thing from the cases concerns the roles of different ministries. Typically, there are several key players, but the environment ministry is not necessarily dominant and economic ministries including not only energy but industry and finance have large roles. In other words, it is not that any one ministry is dominant but that efforts have been made to incorporate broader more integrated perspectives into policymaking. The direct role of finance or treasury agencies in WA is notable, particularly where subsidies are a dominant instrument. Likewise, the integration of some aspects of innovation, energy and climate under one ministerial roof (GB) is noteworthy. The contrast with most experience in Canada – where industry, finance, environment and energy tend to live in ministerial silos – is striking.

The larger role for economic ministries and in particular energy and finance also goes to the question of expertise, alluded to already above. So does the role of powerful provincial crown corporations that often embody the bulk of available expertise and possess the potential to have an outsized influence on provincial policy choices. One thing that seems clear is the very large need for technical, economic, environmental, financial and legal expertise. But perhaps a bigger question that emerges strongly from the cases is the limited expertise in policy systems as a whole. This theme emerges particularly strongly in WA. Taking it back to the question of central planning, the expertise gap may be one of the most daunting challenges.

Leaving organizational questions aside, there remains the question of choice and application of governing instruments. Any number of complex questions stand out. What role, if any, does carbon pricing play both in policy and in regulatory processes? How do carbon and energy markets interact, and how will energy markets be coordinated with domestic and international emissions trading and offset mechanisms? If the consequences of prices are too hard to bear politically, what is the practical scope for subsidies? Are subsidies potentially perverse because they mask price signals or continue to leave consumers and citizens essentially ignorant of the real implications of the goal of net zero? Regulations and standards provide some measure of certainty as to outcomes but, virtually by definition, that certainty comes at the cost of lost flexibility and adaptability to changing circumstances.

4.5 Driving reform: who is in charge?

The net zero goal appears to have caught on much more firmly than any previous wave of climate preoccupation. What or who is driving it? While public opinion in all three jurisdictions is a factor it is also well known that public opinion is often weakly grounded in factual reality (WA) and when it comes to climate, can be thin and fragile when practical realties or other priorities are brought to bear (GB). International pressure is a factor but governments have largely ignored solemn commitments going as far back as Rio in 1992. Traditionally, third party activists have been the principal drivers calling for action but with some exceptions they have elicited as much political hot air from governments as real action. This time around the private sector appears much more committed – whether it be activist investors, technology developers or energy delivery companies genuinely seized of the need to step up to the challenge and take advantage of emerging business opportunities. So there is lots of energy around clean energy but the question is how does it get channeled?

The role of legislative bodies or other less formal deliberative forums to drive change arises in all the cases. In GB most strikingly there has been a surfeit of legislative actions over the past two decades. Legislated targets do have the effect of concentrating minds and the fact that legislative bodies have acted is suggestive of some measure of cross-partisan agreement. But as with targets generally it seems easy enough to get agreement on the goal, but harder to achieve it in implementation.

In the realm of practical reform, the centre of the action is the political executive advised to one degree or another by various bodies. In one case (NY) there is very tight control in the Governor's office that extends to de facto control of the regulator, with growing policy influence of environmental imperatives to the exclusion of economic and traditional utility concerns. Alongside these relationships is a newly created body to advise the political executive on implementation of state climate legislation. This arrangement appears to give short shrift to notions of inclusiveness, transparency or due process.

One issue that remains in the background in NY in particular traces back to the earlier discussed problem of the need for lightning speed weighed against orderly process. Whether NY can pull this off while maintaining public support is yet to be seen.

The experience in GB and WA suggests a rather different approach that starts with more active parliamentary involvement that can serve, among other things, as a learning process for both political and bureaucratic officials. The more "open" legislative approach naturally extends to more open public debate including frankness about implications, consumer feedback and "layered" consultation processes beginning at a high level and extending to more granular and actionable questions.

One theme that runs through all the cases is the vexed question of how to achieve a truly systemic approach. All commentators appear to agree that such an approach is essential to account for the multiple interactions within the energy system itself. The GB case illustrates how hurried approaches can have the effect of going wrong or at least encountering unanticipated consequences and, thereby, leaving legacies that may impede future progress and are difficult to unwind.

We have already discussed the challenges to whole system planning. GB and WA offer two different perspectives. On the one hand, given the inevitable divergence of interest and perspectives across the whole system there is merit in incremental, step by step approaches involving pilots and experimentation. On the other, as in GB, the gradual accretion of multiple measures risks creating a highly complex, confusing and internally contradictory set of policies and measures. Against this backdrop, the NY experience appears to offer an example of a more coordinated approach that takes into consideration how existing legislation, policies and programs can be aligned with new legislative measures.

4.6 Jurisdictional conflict and cooperation: roles of national and sub-national governments

Despite the fact that two of the jurisdictions we examined – NY and WA – involve states which are part of federal systems, questions of jurisdictional cooperation or conflict are not front and centre in the cases. Where they have arisen, though, there would appear to be relevant implications for Canada.

WA has seen national-state conflict over natural gas pipelines involving what was seen as federal intrusion in state jurisdiction. While in substance this has little bearing on the work here, it is a cautionary tale about blowback over the reality or perception of federal overreach.

More germane is the observation in the case that the creation of a national energy market, interconnection of state grids (mainly in the eastern part of Australia) and the emergence of climate change are increasingly pushing energy policy into the national arena. This point is worth some reflection given that similar pressures are arising in Canada.

The integration of state-based systems to form a national energy market remains nascent but has brought challenges. To date there has been considerable debate about providing the federal regulator with authority over bulk transmission. This was reflected in legislative proposals at the national level (WA) but due to a number of factors these changes have not yet come about. All of this begs the question of the appropriate role of the federal government, whether in process or substance.

Australia has created noteworthy mechanisms for fostering and managing intergovernmental discussions on energy. This was handled for some time by the Council of Australian Governments (COAG) Energy Council. In May 2020, the COAG was replaced by the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting.

Efforts in NY to move toward net zero have been almost wholly dominated by debate and action within the state but with two important exceptions.

New York is one of two states with a single-state system operator (RTO/ISO) regulated by the Federal Energy Regulatory Commission (FERC). NYISO tariffs and markets are regulated by the FERC and the NYISO, as is the case with other ISOs, focuses on system reliability. The state has limited authority over the NYISO and relies on pressure exerted through the New York utility transmission owners to influence policy. This arrangement has had a direct impact on downstream energy service delivery, through, for example, changing definitions of what constitutes bulk power (the inclusion of certain DERs).

Of interest is that more climate activist states, including New York, Massachusetts, and Connecticut, have concluded that achieving GHG emissions targets and integrating DERs requires an integrated approach to infrastructure planning, operations, and markets between the FERC-regulated ISOs and state-regulated distribution companies. The NYISO and New York distribution utilities have been working on better coordination on integration (planning, operations and market design) of distributed and large-scale renewables. All of this cross-jurisdiction cooperation appears to have had some success in strengthening the transmission grid.

Going back several years, FERC also undertook major efforts to introduce competition into the natural gas industry and this has had cross-jurisdictional implications. These policies enabled state regulators to allow larger customers to arrange their own supplies or acquire a delivered supply service from a marketer.

Interestingly, in only one situation has a municipality (the City of New York) emerged as a dominant or consequential player. This highlights the difference between small town, rural or resource region energy profiles compared to urban areas (NY). In addition, in WA, attitudes of local *communities* toward distributed solar are part of the debate. And in GB the case makes passing reference to local roles (potential as much as realized) in land use planning.

4.7 What works and what doesn't

The cases offer interesting possibilities as well as cautionary tales respecting what works and what doesn't. What they don't and can't do is tell us much that is definitive because the serious drive to decarbonize any economy beyond the upstream power system has a very short life as of yet. Little is known about what processes will generate effective policy and regulation and less yet is known about the consequences for emissions or system functionality, much less cost.

The longest experience is in GB where they have been working with legislated targets since 2008. But there the primary focus has been on eliminating coal from the power system and introducing a variety of renewables. Nowhere can we see the implications for power systems predominantly based on renewables, storage and distributed resources (although we can see that GB appears to be passing a tipping point beyond which the consequences for system integrity and affordability may be dire); of power systems substituting for the approximately 80 percent of end use energy still provided by hydrocarbons; of natural gas systems either being eliminated or carrying large volumes of low- or GHG-free fuels such as renewable natural gas or hydrogen; and of transportation energy systems wholly reliant on electric power or hydrogen and becoming, in effect, integral parts of power systems.

What we can see is different approaches to the process and substance of reform but, again, with little physical evidence so far of completely transformed energy systems it is at best speculative whether the reform processes in the three cases will prove viable in the end.

All of this said, there are early lessons to learn and promising practices to consider.

The need for approaches that integrate energy and climate imperatives. One foundational approach is the idea of legislating specific targets. This apparently has had the effect in NY and GB of concentrating minds on the problem of achieving net zero. But it has fallen well short of reconciling the overriding emissions priority with the many other objectives which energy systems must fulfill and it risks reducing such objectives to second order considerations – until things go wrong, which they have clearly begun to do in GB.

The need for inclusive, rigorous but adaptable planning that corresponds with market-based systems. In all jurisdictions there is recognition of the vital role of planning, but exactly what that means in market systems where a great number of essential technological solutions remain far from tried and true is unclear.

In all cases there has been growing attention to planning. Planning can range from broadly indicative to highly prescriptive. Indicative planning gives only weak guidance but in the face of technological and behavioural uncertainties it would seem that prescriptive planning, especially that based on fuel or technology determinism, is a very risky approach.

Planning can be aimed at producing a "plan" or it can be a continuous process. Plans have a habit of either being put on shelves or becoming their own masters and becoming set in stone even when surrounding conditions may render them obsolete. Continuous planning processes are inherently more flexible, but they are ponderous and come with a cost of inhibiting investor certainty and being hard to reconcile with legally binding targets.

Planning can be highly centralized keeping firm control and a sharp focus on specified outcomes. But the corollary of centralized planning is a narrow base of expertise and knowledge of the multitudinous variables that underlie the functioning of energy systems including the preferences of people, whether as customers and citizens. Alternatively, planning can be open and inclusive, bringing in more perspectives but adding complexity, raising questions of who is or is not "included" and, inevitably, functioning relatively slowly.

The need for whole system thinking – both in energy system and machinery of government terms. Whole system thinking remains an elusive goal in all three jurisdictions. Several efforts can be seen that attempted to merge multiple perspectives and sources of expertise and some of this shows promise. But while adding more perspectives should bring greater wisdom it also adds complexity and ambiguity and inhibits speed. And, of course, what constitutes the "whole system" varies. For some, the debate centres entirely on the electric power system but the "system" necessarily extends to natural gas, heat and mobility systems, and, given the vital role of energy in society, the boundaries get pushed steadily outward to encompass broader economic questions such as competitiveness, social questions such as equity and questions of fiscal management. In the end it comes down to the political judgment of leaders – good for democratic accountability but filled with the perils of what may well turn out to be bad judgments based, ironically, on narrow and short-term considerations.

The need to recognize the strengths and limitations of both incremental and comprehensive processes of reform. All three cases illustrate various approaches to integrating policymaking with operational questions such as regulation and the design and functioning of incentive systems. The WA case suggests that there is merit in incremental approaches, in effect learning by doing. The GB case, on the other hand, shows how incremental approaches can lead to such accretion of measures that the whole thing becomes incomprehensible. None of the cases provides us with a sure model of how best to allocate responsibility and accountability among various actors, but in all circumstances there is a need for comprehensive thinking and large scale policy at the system level within which numerous close to the ground actors can undertake incremental approaches in various areas.

The need to include environmental organizations, communities, citizens and other parts of civil society at the right time and on the right questions. All of the cases show us varying degrees of citizen engagement – largely through advocacy groups – and varying degrees of success. Where the focus is on relatively simple challenges such as designing small local systems or driving particular technologies, citizens may become engaged and become sufficiently knowledgeable as to be constructive contributors. But at the big system level and for highly technical questions that may concern power system physics or complex business or regulatory models, citizens may be little more than bystanders. When they react negatively to price increases or oppose new infrastructure, they may also be inhibitors of change.

In short, the cases have given us a few tentative answers combined with a large number of very useful questions. These sorts of questions give us considerable grist for the last section of the report where we consider what all of this may mean for Canadian jurisdictions, what potential roadmap Canada could follow for electricity and gas utility regulatory reform, and what the respective roles and responsibilities of policymakers, regulators, different levels of government, industry and other players might be.

5 Insights and recommendations for Canada

This section builds on what we can learn from the three cases and incorporates insights from research and engagement in recent years at Positive Energy, to place the lessons in the distinctive context of Canada.

In the earlier section, 'Challenges and Tensions across Different Jurisdictional Contexts,' we noted that most jurisdictions face the same challenges and tensions among policy objectives, but their contexts vary widely. We identified four aspects of context that are particularly germane: physical realities; constitutional and legal arrangements; political cultures; approaches to government machinery and the respective roles of legislative bodies, the political executive and regulators. Within Canada, of course, these contextual factors vary widely across provinces.

For Canada, several aspects of the context stand out. The country is:

- a federation in which provinces possess most of the constitutional jurisdiction over natural gas and electricity delivery; provincial utility regulators dominate the system with little to no involvement of the federal energy regulator.
- a market-based system traditionally dominated by vertically integrated utilities operating under cost-of-service regulation. In most provinces, the electricity sector is dominated by a vertically integrated provincial crown corporation, or the sector operates as a hybrid system as is the case in Ontario with unbundled provincial crowns for generation and bulk transmission, and municipally-owned local distribution companies. In most provinces, power rates are at least in part market-derived.
- composed of highly diverse provincial and territorial energy profiles and market systems across the country; lack of respect or recognition of cross-country diversity can generate conflict and inhibit collaboration among jurisdictions.
- geographically large with a small, dispersed population outside of a few major cities and with seasonal temperature extremes.
- In the process of reconciliation with Indigenous peoples, for whom engagement, partnerships and ownership in energy projects is a high priority as a means of economic reconciliation, energy equity and community development.
- a large oil and gas producer with substantial reserves; the secure natural gas supply has a bearing on both electricity generation and the opportunities for gas in energy delivery, and affords opportunities for blue hydrogen production and use.
- economically integrated and interdependent with the United States; bulk electricity trade and infrastructure tend to flow north-south rather than across provincial and territorial boundaries.

To this we can add that insofar as commitments to net zero are concerned, in the past few years the federal government has been the most prominent player but by no means the only one. Provinces and territories are diversified in their approaches to emissions reductions and net zero commitments, but most are at least signalling an intention to act – and for some, aggressively. Municipal governments, in particular large cities, are doing the same.

At both levels of government, energy and environment/climate tend to exist in separate ministries, as do finance and innovation/industry (at the federal level, responsibility for infrastructure also rests in a separate department). Utility regulators generally operate under the auspices of energy departments, while emissions reductions targets and policy emerge from environment/climate departments, which generally have limited experience and understanding of utility regulation and downstream energy delivery systems. These institutional arrangements challenge coordination and the development of integrated effective approaches.

Against this backdrop, we have organized this section using the key insights and themes developed in the previous section.

5.1 Challenges, opportunities, and costs in market-based systems – and the alternative of centralized control

No jurisdiction has adequately confronted the conundrum of how largely market-based systems (driven mainly by supply and demand, prices, private investment and customer response) can be reconciled with the demands for certainty implied in legally binding commitments to net zero by 2050 (or any specific date).

The potential for highly centralized control nationally is particularly limited in Canada because most of the relevant jurisdiction for electricity and natural gas delivery rests in provincial hands, provincial gas and power systems vary in their profile and market structure, and inter-jurisdictional cooperation is at best sporadic. If Canada is to overcome these constitutional, market and cultural facts, governments will need to acknowledge that the net zero challenge is unique in our history – in its scale, complexity, and speed – and that long-standing habits of governance cannot be reconciled with net zero by 2050.

- Canadian governments at all levels – federal, provincial/territorial, municipal, Indigenous – need to recognize that climate and net zero pose a unique and unprecedented issue that challenges several long-standing assumptions about the way we organize and manage our energy economy. An unprecedented degree of inter- and intra-jurisdictional coordination will be essential. Proposals to move toward a more dirigiste and centralized approach need to be carefully but skeptically considered. This is where the conversation over energy system policy, planning and regulatory reform needs to begin.

5.2 Physical pathways: avoiding one size fits all

The unique physical circumstances of any jurisdiction – sources of supply, drivers of demand – will govern what is possible. Circumstances in Canada are often very different across the country as well as from those in the three cases. In short, there is no single Canadian model at present, nor should there be a single model imposed in the future.

- Approaches to energy system policy, planning and regulatory reform need to be anchored in the principle of respect for difference. What is common is the shared desire to reduce emissions and to identify pathways that speak to the unique strengths, limitations and opportunities within each jurisdiction. Crucial to this will be avoiding the temptation of technological or energy source determinism, but rather, putting emissions reductions potential and incentivizing innovation, behaviour and market structures that put lowering emissions at the heart of decision-making.

5.3 Policy objectives and practical realities: bridging the disconnects

In all energy systems, precedence must be given to underlying energy requirements for system integrity and the political, social and economic requirements for affordability and competitiveness. Failure to account clearly for these realities will create profound risks of failure.

- Integrated approaches that attend to both climate and energy imperatives will be key, even if those multiple imperatives inhibit the drive to net zero in the short term. In the long term, electricity and natural gas utility regulatory modernization that attends to affordability and system integrity will help ensure the durability of reforms and the effectiveness of emissions reductions efforts in the long term.

The desire for speed, control and predictability in the transformation comes up hard against countervailing (and growing) forces in Canada demanding openness, inclusion, due process, and community engagement and support for new infrastructure, energy sources and technologies. These forces are set to grow even more as Indigenous governments and communities assume larger roles in energy delivery. These forces will prove irresistible and policymakers will have no choice but to accommodate them even if the consequence is a slower and messier – but ultimately more durable and effective – process of transformation.

- Durable effective change requires that the process and substance of reforming electricity and natural gas delivery systems be inclusive, even if it means growing complexity and slower speed of execution than desired in the short term.

5.4 Regulatory effectiveness in a sea of instruments and institutions

Policymakers need to closely examine how to redesign public decision systems – including ones involving independent regulators – so they can account for a growing list of imperatives while acting based on expertise and evidence and with high degrees of transparency, due process and accountability to the public. This doesn't mean starting from scratch or throwing the baby out with the bathwater, but it does mean redesigning such systems in light of current imperatives.

- Central to this will be incorporating emissions reductions (as well as other policy priorities as appropriate) into regulatory agencies' mandates. Regulators' close to the ground understanding and expertise is critical. Policymakers must do this through proper policy, legislative and regulatory direction and, crucially, avoid political interference in regulatory decisions for individual applications.

Policymakers face the challenge of developing organizational models that permit system thinking while making such thinking operational – all in the context of greater market and social uncertainty, technological innovation and unpredictability between policy intentions and real-world outcomes. Rising to the challenge will require a multitude of new approaches, processes of adaptation and continuous improvement, building on what works and abandoning what doesn't.

- Approaches that bring together the necessary expertise across various organizations and sectors will be pivotal, as will mutual learning and evaluating what works and what doesn't on a continuous basis.

Public sector capacity, including expertise, organization and resources – or the lack of it – may prove to be one of the biggest constraints to the transformation.

- Governments must address the organizational and capacity imperatives and they need to do so urgently. Developing better understanding of energy utility regulation within and across policy departments at both federal and provincial levels is critical for Canada.

5.5 Driving reform: who is in charge?

The most salient imperative of course is responding to the climate challenge – driving toward net zero. But this is more than just an environmental policy problem and requires skills and knowledge well beyond environment departments. Insofar as most strategic and operational questions are concerned, it requires skills and knowledge from energy, economic and finance departments. Moreover, it cannot be resolved by the political executive acting on its own. It is striking from the cases the extent to which multiple ministries are active and decisive players: notably environment ministries, energy ministries, economic ministries and finance ministries. In a different but related vein, we see active engagement by legislative bodies on an ongoing basis both as the sources of legislative authority but almost as important, as deliberative forums that facilitate learning and the building of durable consensus.

- Approaches that bring together the whole of the machinery of government are vital. Breaking down silos between federal and provincial/territorial governments and among federal/provincial/territorial departments – energy, environment/climate, finance, innovation/business – will be especially important for Canada in reforming electricity and natural gas delivery systems; so will active engagement of legislatures as forums for deliberation, learning and consensus-building.

5.6 Jurisdictional conflict and cooperation: roles of national and sub-national governments

The cases tell us only a limited amount about the respective roles of different levels of government: in GB a unitary system and in WA and NY dominant roles for state governments, with a few important and sometimes controversial roles for the national government. Similarly, given the scope of the cases, they tell us little about cross-jurisdictional cooperation among sub-national authorities. But we know that in Canada the extent to which provincial governments cooperate will prove vital in many cases. Diverse resource endowments and the need for load balancing will compel cooperation on electricity trade and associated infrastructure. Less tangible perhaps, but also important, is the potential for learning across jurisdictions.

The federal role is both critical and limited. In Canada, the federal role in establishing carbon pricing is foundational, as are the federal responsibility for national/international commitments and the federal spending power. The federal government can enact regulatory measures such as emissions caps and fund subsidy arrangements to reduce emissions as long as their fiscal capacity will sustain it. By and large, though, the diversity of provincial circumstances, the established division of powers and the deep technical expertise required in downstream electricity and natural gas system management argues for a federal role in this area to be dominated by suasion, coordination and information management.

Of these, coordination is especially important: federal climate policy measures may have consequences – intended and unintended – on the downstream electricity and natural gas system. Where this is the case, ensuring federal policy and regulatory choices are developed with a fulsome understanding of the impacts on downstream energy systems will be vital. So will ensuring that subsidies are based on emissions reductions potential, not technology or fuel determinism. What further roles the federal government might take in bulk power transmission (an existing area of federal jurisdiction where it crosses provincial boundaries) is an interesting question and a potential source of controversy.

A growing question concerns the role of local governments, which have become ever more active and ambitious in trying to shape electricity and natural gas delivery systems, but often without the benefit of adequate capacity and expertise and, potentially, misalignment with larger regional realities and provincial/territorial policy frameworks. Local governments have potentially important roles to play but they will need stronger provincial/territorial frameworks, much greater capacity (particularly for smaller governments) and better tools if they are to play a constructive role.

One of Canada's distinctive if not unique circumstances concerns the growing role of Indigenous governments and communities as shapers of policy and regulation, as decisive players in the approval of infrastructure, as partners or owners of facilities and, increasingly, as regulators.

- New approaches to federal/provincial/territorial and Indigenous government cooperation – ongoing planning, with systematic high level political engagement and intensive bureaucratic cooperation – will be vital to success.

5.7 A roadmap for action

We can see numerous promising avenues in the cases that may well prove to be effective. But despite at least two decades of active climate policy, most jurisdictions have yet to see fundamental structural change in their electricity and natural gas delivery systems (most efforts have gone into driving emissions out of upstream power, oil and gas and industrial systems). Many approaches to planning and regulation can be found in the cases. Some appear to work, others less so. But in terms of the metrics of future success in the drive to net zero the jury is still out.

Arguably, Canada will best benefit by taking advantage of its diverse constitutional and legal arrangements, living with the messiness of multiple jurisdictions, but finding ways to better coordinate and focus attention on what we can learn across the country.

Based on this, we can articulate a possible roadmap for Canada. Central to our thinking is the need to foster collaboration, coordination and mutual learning across the country. In the first iteration of this report (spring 2022) we argued for a national collaborative forum that brings together the necessary expertise, authority and capacity for action, but with a clear time-limited mandate, objectives and commitment to action.

Over the course of the past year, policymaker attention has shifted rapidly in the direction of critical minerals and supply chains for electrical components, and a number of new tables have emerged (e.g., Regional Energy and Resource Tables). In this evolving context, a single national table to focus on downstream electricity and natural gas delivery would likely stretch the capacities of all governments. Instead, we propose a number of more lightly institutionalized forums both national and within sub-national jurisdictions, bringing together policymakers, regulators, Indigenous communities, industry and civil society, as appropriate.

But multiple tables does not mean that groups need work in isolation. We recommend creation of an overarching pan-Canadian mechanism for sharing and collaborating. Such a mechanism would not control but could help to foster alignment and coordination on shared challenges and opportunities. It would also serve the crucial role of information hub.

At present there is no single 'table' capable of mobilizing the focus and capacity to develop effective, credible, integrated and actionable approaches to net zero electricity and gas delivery system policy and regulation. There are, however, a multiplicity of tables, each with potential roles to play (e.g., CAMPUT, Energy and Mines Ministers Conference, industry associations, Indigenous and civil society organizations, academic initiatives, etc.).

In short, there is potential to mobilize these forums for collective impact, and, as noted, create a mechanism to facilitate a flow of ideas among them. There are several reasons for encouraging such a flow:

- A cross jurisdiction perspective would prove valuable. Canada has 13 distinct contexts (provinces and territories) and hundreds when we include Indigenous communities. But none is as distinct as some may think. As we have noted earlier, many of the challenges and tensions that bedevil the process of change are common across jurisdictions.
- There will be many mistakes and failures as well as successes. All of these are potential resources for others to learn from.
- There remains a pressing need for a larger voice (or set of voices speaking similar languages) to make the case for the scale, complexity and cost of the transition in the electricity and natural gas delivery systems – to policymakers and to the public.

Ideally, the mechanism we propose would go beyond simply being a central source of information – it would also help to coordinate and spur action and reform. Among the topics for attention:

- A realistic assessment of the scope, scale, cost and timing of needed change in downstream electricity and natural gas systems.
- The potential roles of power, piped fuels, heat systems and utilities in different scenarios, and the opportunities to optimize the gas and power systems for collective emissions, affordability, reliability and resilience impact.
- The costs and practical implications of retrofit versus new development.
- What we know about actual consumer and developer responses in the marketplace.
- The absorptive capacity of key players, both governments and private actors, as well as consumers and citizens.
- Innovations in policy-regulatory relations and regulatory system design, including with an eye for interesting developments beyond Canada.

5.8 Final words

Governments, industry and civil society in Canada and abroad are increasingly aligned on the ambitious objective of net zero by 2050. Natural gas and electricity players in the energy delivery system can play important roles in pursuing this goal. In Canada as elsewhere, policy and regulatory frameworks will need to be reformed to maximize the potential for gas and power companies to contribute to net zero. It is crucial to examine areas for reform *across* both electricity and natural gas delivery to enable emissions reductions and system integrity in end use energy delivery.

This study's analysis of reform efforts in the United States, Australia and the United Kingdom underscores the shared challenges and tensions of policy, legislative and regulatory reform. Questions of cost, political acceptability, system integrity, intergovernmental collaboration, the role of regulators vis-à-vis policymakers, technology readiness, and customer/citizen/investor support loom large. Getting the process of reform right is crucial, as it contributes both to widespread support for needed changes and to the ultimate effectiveness of reforms.

Given Canada's constitutional, energy, economic, demographic and social characteristics, collaborative approaches bringing together key policy, regulatory, corporate, Indigenous and civil society players will be crucial to success, as will maintaining a sharp focus on system integrity and affordability alongside emissions reductions goals.

uOttawa

POSITIVE ENERGY

CASE STUDY 1: GREAT BRITAIN

Kathryn Porter, Watt-Logic

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1 Introduction

Great Britain's net zero journey began with its Kyoto Protocol commitments to secure a 12.5% reduction in greenhouse gas emissions from 1990 levels between 2008 and 2012. A more ambitious target of a 20% reduction in CO_2 by 2010 was subsequently established by the UK Government, initially supported by an energy tax linked to carbon emissions associated with different fuels (the Climate Change Levy, introduced in 2001), and a subsidy scheme for large-scale renewable generation (the Renewables Obligation, introduced in 2002). A more wide-reaching approach was implemented in the Electricity Market Reform ("EMR"), launched in 2011. As a result, the UK's carbon emissions fell by 44% between 1990 and 2019, and renewable generation capacity increased from 3.1% of the total in 2000 to 29.5% in 2020 with the amount of electricity generated from renewable sources increasing from 2.8% to 43.1% over the same period.[1]

The British market is now at a key point in its transition. Penetration of renewable generation has grown to a degree that the design and operation of electricity networks needs to evolve, while at the same time, legally binding net-zero targets are driving the decarbonisation of heating and transport. The intermittency associated with renewable generation did not present much of a problem when there was very little such capacity on the system, but now the amount of intermittent generation has reached a level where both the practical challenges and costs have become significant.

A significant investment in back-up capacity is required, but the economics of that back-up capacity are seriously impaired by low utilisation rates and low wholesale prices when wind levels in particular are high. Since there are times when intermittent renewable generation is producing close to zero electricity (for example in the winter, the sun sets before the evening peak, and anti-cyclonic weather systems result in still conditions), a significant amount of back-up capacity is required. This capacity must be paid for.

As the Government has announced plans to quadruple the amount of offshore wind capacity by 2030, the challenges presented by intermittency will become more pronounced. While the Government has also set a target for the electricity system to be net zero carbon by 2035, this target is explicitly subject to maintaining security of supply, and therefore there are some reasonable doubts that it can be achieved. This has several implications for electricity and gas networks:

(i) how demand for gas and electricity will evolve in response to net zero policies;

(ii) how to achieve whole system thinking and design when networks are disparate (separate operations for the high voltage transmission system and lower voltage distribution networks);

(iii) how these networks are accessed and paid for;

(iv) how these changes fit within the price control framework;

(v) how security of supply is delivered; and

(vi) how trade-offs between costs to consumers and environmental targets are met.

This case study has been based on a survey of various market reports, interviews[2] with industry participants (some of whom asked to remain off the record due to having protracted approvals processes for being quoted publicly) and stakeholder responses to Government, Parliamentary and regulatory consultations, which are in the public domain, as well as the author's own knowledge of the market.

1 Renewable generation in 2020 was boosted by both additional capacity and favourable weather conditions.

2 Interviews were conducted over videocall and email with five energy professionals including representatives of renewable generators, a former energy regulator, a member of an energy think tank, and other energy consultants, to build on the written and oral evidence of 84 people and organisations to the ongoing House of Lords inquiry into Ofgem and Net Zero, which were studied in detail for this report.

2 Gas and electricity markets in Great Britain

2.1 Background: market and governance context

The Government[3] of the United Kingdom of Great Britain and Northern Ireland based in Westminster passes the relevant legislation. Devolved legislatures[4] can pass supporting legislation (Westminster laws have precedence). Northern Ireland is part of a single electricity market in the island of Ireland, and therefore has a different market structure to the rest of the United Kingdom. For this reason, this case study will focus on Great Britain.

There are various layers of local and municipal government, but these have limited powers, and have no role in setting energy policy or the direction of energy regulation. Although London is by far the largest population centre in the UK, and therefore a major energy demand centre, the Mayor of London[5] is not active in influencing energy policy at the national level and has limited powers to affect energy within the city – for example, the Mayor could not create an alternative price control for energy networks in the city, or establish new subsidies for renewable energy (Mayor of London, p9-10). London has set up its own energy supply company (in January 2020), which operates under a white label arrangement with an established supplier. By 30 September 2021, the company had 6,310 customers, out of about 3.38 million London households, which represents a very low market share).

The main role of local government in the energy transition relates to buildings as local authorities control the planning process. Several local authorities have developed requirements for new residential developments to be part of emerging local heat networks, but these are proving to be unreliable, leading to high levels of customer dis-satisfaction (Heath, 2021). Some local authorities, particularly in urban areas, are also considering investments in solar generation located elsewhere to off-set their demand with renewable generation. This is creating tensions with the residents of the areas in which this generation would be located, as many of these developments involve greenfield sites (Simpson, 2021).

2.2 Energy regulation in Great Britain

The Office of Gas and Electricity Markets, known as “Ofgem” was formed in June 1999, combining the former electricity regulator (Offer) and the former gas regulator (Ofgas). It is a non-ministerial government department and an independent national regulatory authority, recognised by EU Directives. Ofgem regulates the three segments of the gas and electricity markets: generators, network operators and suppliers, and issues the relevant licences to market participants. Ofgem has a number of other responsibilities, including:

(i) administration of various environmental policies;

(ii) administration of the price controls for network companies;

(iii) setting the price cap on default supply tariffs;

(iv) managing the Supplier of Last Resort (“SOLR”) process that ensures customers are not disconnected (i.e., lose supply) when a supplier fails.

3 The UK Government department responsible for energy and climate is the Department for Business, Energy and Industrial Strategy (“BEIS”).

4 In Scotland, Wales and Northern Ireland.

5 Not to be confused with the Lord Mayor of London who heads the City of London Corporation, the governing body of the Square Mile, and acts as an international ambassador for the UK’s financial and professional services sector. The Mayor of London is directly elected by Londoners and heads the London Assembly. The Mayor of London sets budgets for and has responsibility for the following areas within London: transport, policing, fire services, the Olympic legacy and local government administration. Several UK cities have mayors with different levels of powers. Outside of the areas listed, the city mayors have few powers and rely on lobbying central government or devolved legislatures to enact relevant legislation. In addition to the Mayor of London, London (as with the rest of the country) is divided into a number of boroughs or local councils including Tower Hamlets, Southwark and the Corporation of London. These local councils collect a tax known as “council tax” under parameters set out by central government, which contains mechanisms to limit the amounts that can be collected. In cities which have a mayor, the local councils remit a portion of the council tax receipts to the mayor’s office to fund it’s a`reas of responsibility.

Ofgem's primary responsibilities are set out in the *Gas Act 1986* and the *Electricity Act 1989* ("the Acts"), as amended (see Appendix) and are described as being shared, between the Secretary of State and the Gas and Electricity Markets Authority. The principal objective is to protect the interests of existing and future consumers taken as a whole, including:

(a) their interests in the **reduction of gas/electricity-supply emissions** of targeted greenhouse gases;[6] and

(b) their interests in the **security of the supply** of gas/electricity to them.

Ofgem should carry out its functions in the manner it considers is best calculated to further the principal objective, wherever appropriate **by promoting effective competition**.

It should also have regard to:

(a) the need to secure that, so far as it is economical to meet them, all reasonable demands for gas / electricity are met; and

(b) the need to secure that licence holders are able to finance their licensed activities;

(c) the need to contribute to the achievement of sustainable development;

(d) the interests of vulnerable consumers;

(e) promoting efficiency;

(f) protecting the public from dangers;

(g) securing a diverse and viable long-term energy supply;

(h) the effect on the environment of activities connected with the supply of gas and electricity.

Ofgem facts & figures

(Ofgem, 2022)

In 2021-22, Ofgem's operational income was £142.8 million, and its operational expenditure was £129.9 million.

The main source of income is from licence fees paid by market participants, while the main costs are staffing costs.

Ofgem's headcount in 2021-22 was 1,246.

Ofgem's view on trade-offs

(Ofgem, 2020)

Ofgem believes it has several specific trade-offs it needs to consider:

- Balancing the needs of current and future consumers;
- Balancing the distributional impacts of funding policies from consumer bills, taxpayers or others;
- Providing support to early adopters without creating a risk of leaving some consumers behind;
- Balancing the need to do things differently with a recognition that changes may be easier or more advantageous for some people;
- National versus regional action. Regional action can allow for more rapid experimentation and tailoring of policies, but action at the national level can provide better coordination.

6 The original versions of the Acts did not include this language which was inserted as a result of the *Energy Act 2010*, which followed on from the Low Carbon Transition Plan (HM Government, 2009)

Ofgem issued its first decarbonisation plan (Ofgem, 2020), and the Government committed to setting a requirement for Ofgem to carry out its functions in a manner consistent with securing policy outcomes, including "delivering a net zero energy system while ensuring secure supplies at lowest cost for consumers".

In 2021-22, the House of Lords Industry and Regulators Committee[7] conducted an inquiry into "Ofgem and net zero", which considered Ofgem's role in the energy transition and whether changes are needed to its objectives and powers or its role in the wider energy system. The inquiry also examined how net zero relates to Ofgem's other responsibilities such as affordability and the security of supply, how Ofgem considers the interests of consumers, and Ofgem's relationship to Government and Parliament.

The inquiry closed to new evidence in early 2022[8] and the report (Industry and Regulators Committee, 2022) was published in March 2022. Some of the key themes from this evidence are discussed in Section 4 of this report. There were also interesting observations about the role of Ofgem and its relationship with the Government, with several respondents suggesting that the lines between Ofgem and the Department for Business, Energy and Industrial Strategy ("BEIS")[9] had become blurred, and that Ofgem was essentially an extension of BEIS. Several respondents said they felt Ofgem was making trade-offs which they felt were political in nature, and it was raised by a number of respondents that Ofgem is significantly larger than comparable regulators elsewhere in the world. Witnesses also suggested that "the current regulatory regime is slow moving, pedestrian, hard to navigate and not fit for purpose in meeting future energy supplier requirements" (Industry and Regulators Committee, 2021, Q221, pg. 20).

The Committee determined that while an explicit reference to having due regard to net zero should be added to Ofgem's duties, it should not take on any co-ordinating or political role in the transition. However, in its response to the report (HM Government, 2022), the Government rejected the idea that Ofgem's duties needed to change, saying that a new duty is un-necessary since Ofgem's primary statutory duty is to protect the interests of current and future consumers and that these interests taken as a whole, include their interests in the reduction of greenhouse gases. In other words, the Government believes that net zero is in the interests of consumers and so Ofgem is already required to take account of it.

> "Ofgem will play a significant role and it is important to review its responsibilities to ensure it is not a barrier to a net zero energy system. We do not believe that Ofgem should have a co-ordinating or political role in the transition; it should maintain its existing responsibilities for economic regulation and consumer protection. Explicit reference to having due regard to net zero should be added to its duties, bringing it in line with other regulators and ensuring its regulation does not act as a barrier to decarbonisation. However, it is inevitable that there will be political or distributional trade-offs in Ofgem's meeting its objectives, so the Government must give greater guidance to Ofgem in how to manage these trade-offs in the planned but long-delayed Strategy and Policy Statement."
>
> – House of Lords Industry and Regulators Committee

The Committee echoed the concerns of witnesses that regulatory processes and in particular the price control for electricity networks might act as a barrier to net zero. It recommended that the use of uncertainty mechanisms be re-considered. Ofgem did not make any formal response to the report, so it is unclear whether it will act on this recommendation.

7 House of Lords committees investigate public policy, proposed laws and government activity. A Committee will decide on a subject to investigate, issue a 'call for evidence', asking interested people or organisations for their views, in writing, hold public meetings to hear oral evidence, hold private meetings discuss and study the evidence gathered, draft and agree a report which is published. The Government gives a response which may be followed up by the Committee, and the report may be debated by the Lords.

8 The written and oral evidence is available on the Committee's website: https://committees.parliament.uk/work/1320/ofgem-and-net-zero/

9 Following a re-organisation of Government Departments in 2023, energy is now the responsibility of the Department for Energy Security and Net Zero

> "...the regulatory system can be too slow and difficult to change. Ofgem is often too cautious in its approach to allowing new business models into the retail energy market... We are also concerned that network price controls have the potential to stifle investment at the exact moment it is most needed. Ofgem must be more open to innovative new companies and to enabling investment."
>
> – House of Lords Industry and Regulators Committee

The Committee was also critical of Ofgem's approach to retail market regulation and recommended the introduction of banking-style regulation. Ofgem is developing an approach to prudential regulation within the sector, but this is being met with strong resistance from some suppliers and consumer groups who fear, correctly, that the measures will increase costs to consumers in the short term. Other suppliers, notably Centrica, the market leader which already voluntarily ringfences consumer credit balances, argue that these costs are smaller than the costs of supplier failures which are partly socialised. These measures are still the subject of industry consultations and no final decisions have yet been made.

> "Consumer protection should remain central to Ofgem's work. The recent spate of failing energy suppliers is evidence that it has failed in this regard, having focused excessively on customer switching as one narrow measure of competition in the sector. This has led to short-term price competition that, combined with a lack of regulation over the sustainability of companies who have entered the retail energy market, has created greater cost and uncertainty for consumers...Ofgem needs to implement a robust approach to the licensing and supervision of suppliers, akin to the supervisory regime that financial services are subject to—including capital requirements and a fit and proper persons test—while remaining open to new business models that benefit consumers."
>
> – House of Lords Industry and Regulators Committee

In their report released the summer of 2022, the House of Commons BEIS Select Committee reported on its "Energy pricing and the future of the energy market" inquiry, (BEIS Select Committee, 2022) which was highly critical of Ofgem's regulation of the retail energy market:

> "Ofgem has proved incompetent as the regulatory authority of the energy retail market over the last decade. It allowed suppliers to enter the market without ensuring they had access to sufficient capital, acceptable business plans, and were run by individuals with relevant expertise. The regulator enabled poorly capitalised suppliers to be overly reliant on customer credit balances and operate with inadequate hedging, leaving the market ill-equipped to absorb wholesale price increases. The rules that were in place were not enforced and Ofgem did not understand the business models of the suppliers it is mandated to supervise. The Government prioritised competition over effective market regulation and overlooked Ofgem's lack of supervision of this essential market,"
>
> – BEIS Select Committee

> "Ofgem has proved incompetent as the regulatory authority of this complex market, thereby costing taxpayers billions of pounds. The scale of failure and the cost exposure to taxpayers is only comparable to the financial crash of 2008,"
>
> – BEIS Select Committee

The BEIS Committee recommended (among other things) that:

- Ofgem improves its regulatory oversight, its decision-making processes, the use of its enforcement powers, and the quality of its governance;
- Ofgem proactively reports to the Committee on how it is ensuring effective accountability and transparency and to explain key decisions and policy concerns on an ongoing basis;
- Ofgem regularly reports to BEIS on how it is meeting its duties and to inform Ministers of any risks associated with the delivery of Government strategy;
- the Government publishes its long-delayed Strategy and Policy Statement for Ofgem to clearly delineate responsibilities between the regulator and BEIS to ensure transparency and effective scrutiny;
- Ofgem publishes proposals on a capital adequacy regime and monitors suppliers' risk management strategies as standard; and
- Ofgem upskills its workforce to implement its regulatory reforms effectively and proportionately.

The Committee also committed to closer supervision of Ofgem, including over some fairly detailed operational matters. Ofgem was required to carry out additional risk assessments and bring the outcomes before the Committee before making any decisions on implementation. Whether this is repeated, or an isolated occurrence remains to be seen, but this level of operational oversight by a Parliamentary committee is highly unusual.

Ofgem has been widely criticized for its regulation of the retail segment due to the large number of supplier failures – 29 suppliers collapsed in 2021, representing approximately half of the suppliers serving households. The main criticisms relate to failing to anticipate the possibility of significant wholesale price increases, placing constraints on itself that limited its powers to respond flexibly to these price increases, and setting barriers to entry for suppliers that were too low. The consumer group Citizens Advice (Jitendra, 2021) also criticized the regulator for failures of enforcement.

2.3 Industry Codes and self-governance

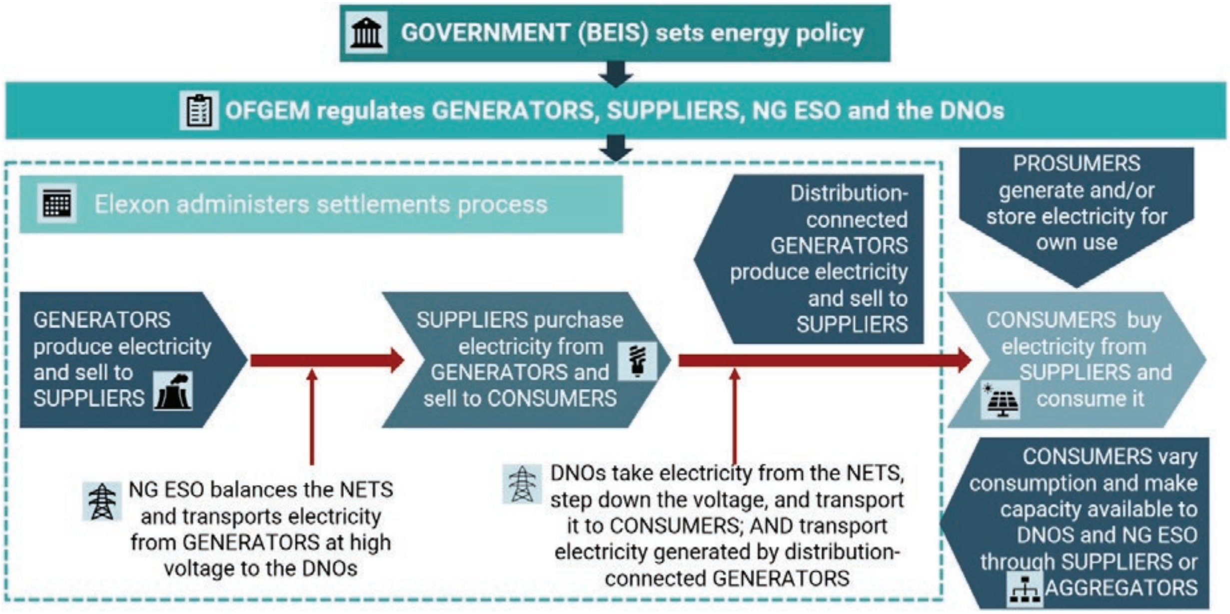
The gas and electricity industries are considered to be self-governing. The standard licence conditions for generators, network companies and suppliers require holders to be a party to one or more of these codes, which set out the technical rules and procedures for the operation of the markets. The self-governing aspect comes from the fact that market participants form working groups which scope out and agree to any changes to these codes – there is no separate oversight or direction of the process. Code reviews can take in the region of 4-6 years to complete. This approach of self-regulation has not been adopted in any other market.

The code modification process is very time-consuming, the codes themselves are long and complex, and new/small market participants tend to be excluded from the process. The codes and their complexity have long been considered a barrier to entry. These concerns have led the Government to present legislation to Parliament (the Energy Bill, (UK Parliament, 2023)) that will create a new governance framework for energy codes that will move the responsibility for code governance to one or more newly created code managers which will be directly accountable to Ofgem rather than to industry, allowing Ofgem to drive strategic change across the codes. The Bill grants Ofgem several new functions including a duty to publish an annual strategic direction statement setting out its vision for how the codes should evolve over the following year; the ability to make direct changes to codes under a limited range of circumstances; the ability to select and license code managers; and the ability to issue directions to central system delivery bodies who are responsible for managing the IT systems that support the energy market. Ofgem plans to carry out a code consolidation and modernisation process to simplify the codes and make them more accessible. Ofgem will be granted up to 7 years to complete the reform process.

2.4 Key actors in the GB gas and electricity markets

The gas and electricity markets contain three segments: upstream – generation of electricity / production of gas; midstream – transportation, storage and trading; and downstream – delivery to customers. There is no state ownership of energy assets.

Figure 1: Structure of the GB electricity market



Source: Watt-Logic

Electricity generators have to be licensed and sell their output either bilaterally under Power Purchase Agreements, or under physical trading agreements. An analogous situation exists in gas for producers with sales under a Gas Selling Agreement or physical trading contract at the NBP.[10]

In the mid-stream there are licensed trading companies, storage operators and network companies. In the gas system there are also shippers who own gas as it is moved through the networks and who manage physical logistics.

Gas and electricity transmission and distribution networks operate as monopolies. For this reason, they are subject to price controls and are prohibited from owning generation or storage assets and are not allowed to sell to end consumers in the same region as their network. Under the price Revenues are linked to Incentives, Innovation and Outputs ("RIIO").

The high voltage electricity transmission system is owned by National Grid plc and operated by National Grid ESO ("NG ESO"), an arm's length subsidiary of National Grid plc. The lower voltage electricity distribution networks are owned and operated by the 14 licenced Distribution Network Operators ("DNOs") who take electricity from the transmission system boundary, step down the voltages, and deliver it to end users.

The gas transmission system is owned and operated by National Grid plc – there is no separation of ownership and operation as there is in electricity. National Grid plc is currently in the process of selling a majority stake in its gas transmission business and is buying an electricity DNO.

10 The National Balancing Point, Britain's virtual gas hub.

There are 13 Local Distribution Zones within eight gas distribution networks in GB as well as independent gas transporters which operate nationally. Currently five companies own and operate these eight distribution networks. Each network operator is required to develop and operate its pipeline network in an efficient, economical and safe manner.

In the downstream segment, energy retailers known as suppliers sell gas and/or electricity to end consumers. Suppliers are required to hold a supply licence.

BEIS and Ofgem are jointly consulting on proposals for an expert, impartial Future System Operator ("FSO") with responsibilities across both the electricity and gas systems, to drive progress towards net zero while maintaining energy security and minimising costs for consumers. The proposal is for all the current NG ESO roles and functions to be carried out by the FSO, and that the FSO should undertake strategic network planning, long-term forecasting, and market strategy functions in gas. Also under consideration are:

(i) the new roles and functions an independent FSO could potentially fulfil in gas and electricity, including in network planning and independent advice;

(ii) the options for organisational models such as a standalone privately owned model independent of energy sector interests, or a highly independent corporate body model classified within the public sector, but with operational independence from government;

(iii) a phased implementation of the FSO, founded on the existing capabilities of NG ESO and where appropriate National Grid Gas.

RIIO

In 2010, Ofgem identified (Ofgem, 2010) that £32 billion of network investment would be needed to deliver decarbonisation objectives. At the time, networks were worth some £43 billion, so this represented an increase of over 75% in the value of Britain's energy networks, effectively double the rate of investment over the previous 20 years.

But this investment would not just be replacing like with like, as was the case in the previous price controls.

Electricity networks would need to be reconfigured to manage electricity flows from a much larger number of smaller renewable plant. In gas here was uncertainty around the long-term challenges facing the network and how it may have to adapt.

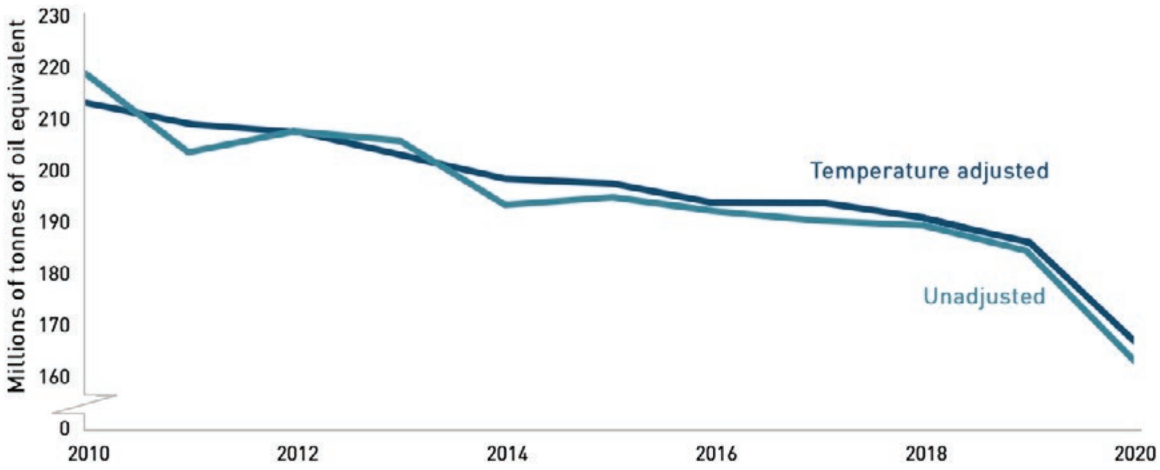
This meant moving away from the RPI-X approach of the previous price control, with its focus on driving efficiency, to a new framework to encourage investment and innovation in the networks while also protecting consumers from un-necessary costs. Network companies have to meet performance targets and are penalised for being inefficient.

For example, if a network firm delivers a project under budget it gets to keep some of that saving as extra revenue, and consumers also gain as the development costs less to build. Similarly, the firm's revenues fall if a project costs more to deliver than expected.

2.5 Demand for energy in GB

UK primary energy consumption has been steadily falling for over a decade and in 2020 reached levels last seen in the 1950s. Primary energy consumption includes use by consumers, fuel used for electricity generation and other transformation. The 10% decline between 2019 and 2020 was driven by the effects of the COVID-19 pandemic, with a noticeably sharp reduction in petroleum consumption as demand for transport fuels fell due to the COVID-19 pandemic lockdowns in place in the UK throughout 2020.

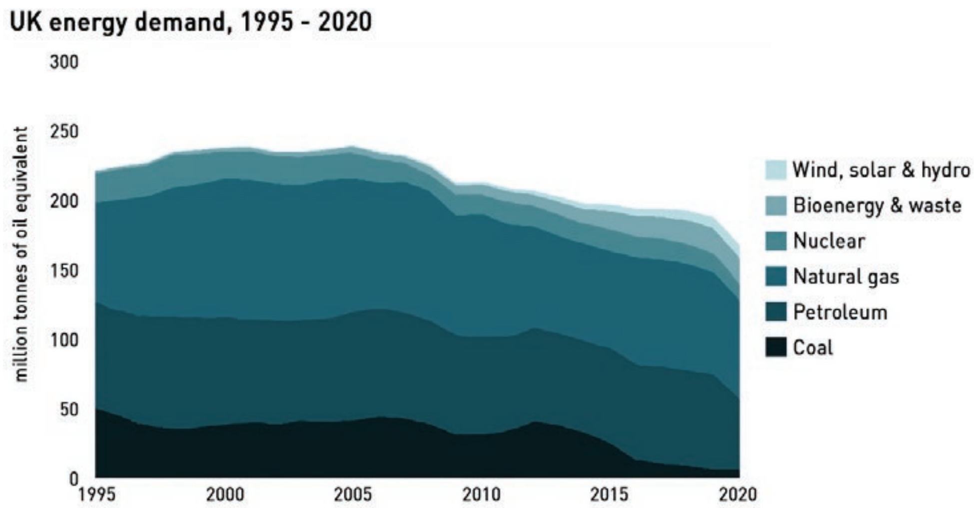
Figure 2: Primary energy consumption



Source: Digest of UK Energy Statistics Annual data for UK, 2020

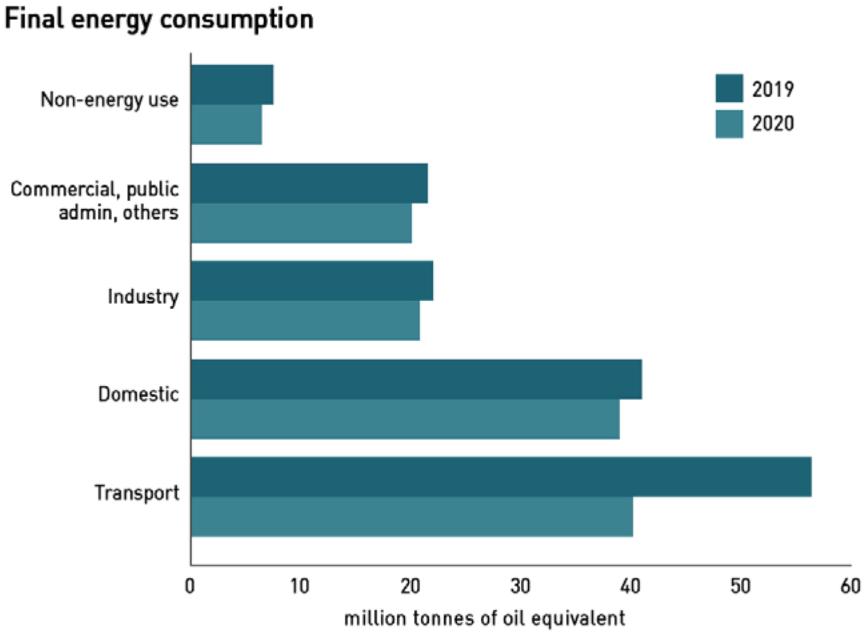
Longer-term, energy consumption has been falling despite significant population growth (between 1970 and 2020, the UK population increased by 6.5 million people), largely through an increase in efficiency as new technologies have been deployed. In addition, the rise of the less energy intensive service sector at the expense of heavy industry has also played a significant part. Household energy use declined by 12% during this period, while industrial consumption declined by 60%.

Figure 3: Demand for energy in the UK, 1995 - 2020



Source: Digest of UK Energy Statistics Annual data for UK, 2020

Figure 4: Final energy demand by sector, 2019 - 2020

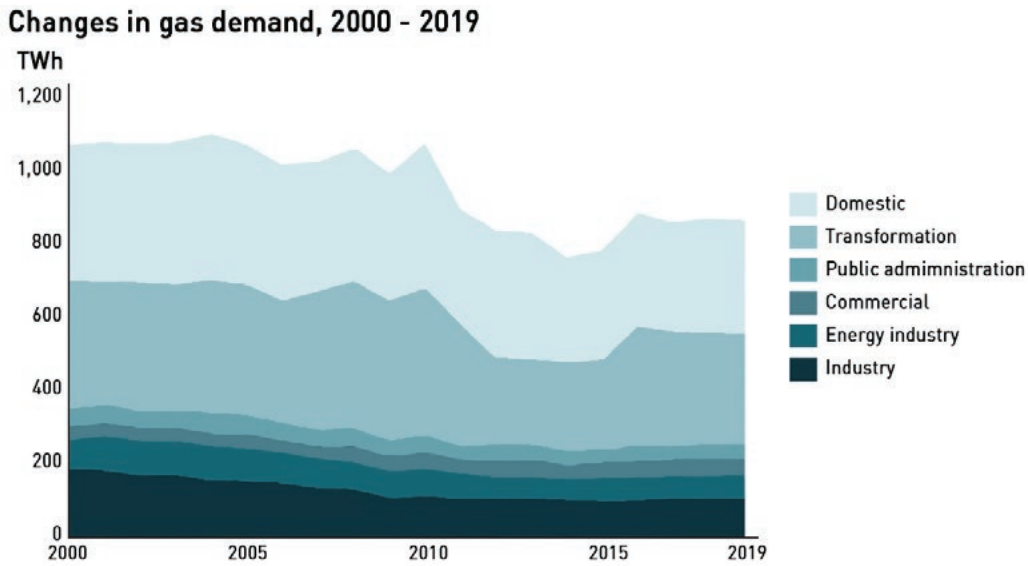


Source: Digest of UK Energy Statistics Annual data for UK, 2019 - 2020

This has been partially offset by a 50% rise in energy use in the transport sector, due to the huge rise in the number of cars on the road and increased economic activity leading to more commercial transportation. In 2020, there were 38.6 million vehicles on the road in the UK compared with 10 million in 1970. There was also a large increase in air traffic.

Demand across all sectors other than the domestic sector fell during 2020 due to the impact of the COVID-19 pandemic. Domestic sector consumption rose by 2.3% reflecting increased home working/schooling. The Government expects that energy efficiencies will continue to offset population growth, so the UK will use about the same amount of energy in 2030 as it did before the pandemic.

Figure 5: Changes in gas demand, 2000 - 2019



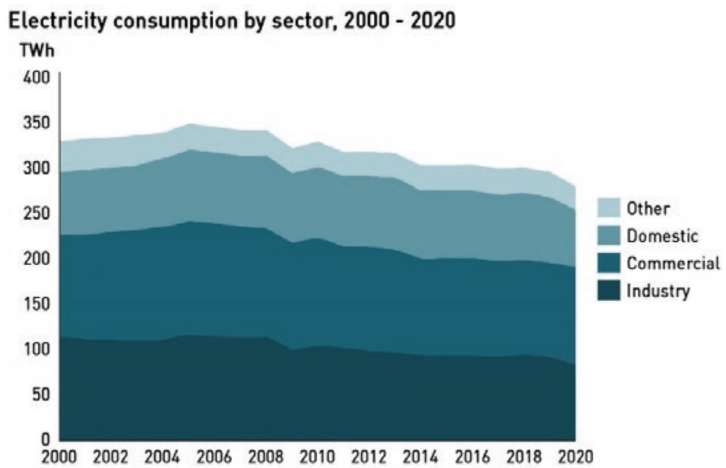
Source: Digest of UK Energy Statistics, 2020

While gas is a critical part of the UK's energy demand its use fell by 22% between 2000 and 2019, driven primarily by a 45% reduction in demand from industry. Demand for generation and domestic demand also declined by 17% and 16%, respectively, despite a rising population and an increasing number of homes, as increased efficiencies, including greater levels of home insulation, drove the decline. Despite the overall downward trend, there have been notable peaks corresponding with weather variations, which generate greater demand for space heating in homes and offices.

Total demand for electricity fell by 10% between 2010 and 2019, with a 13% reduction in domestic demand and a 12% reduction in industrial demand. The larger drop in 2020 was due to COVID-19.

Total electricity demand is larger than electricity consumption since demand also includes electricity consumed in the process of generation or to produce fuel for generation, and transmission and distribution losses.

Figure 6: Electricity consumption by sector 2000-2020



Source: Digest of UK Energy Statistics, 2020

UK installed electricity generation capacity gradually increased between 1996 and 2018, from 73.6 GW to 106.1 GW. Overall, there has been a decline in conventional steam, outweighed initially by an increase in combined cycle gas turbines (CCGT) and more recently by an increase in renewables.

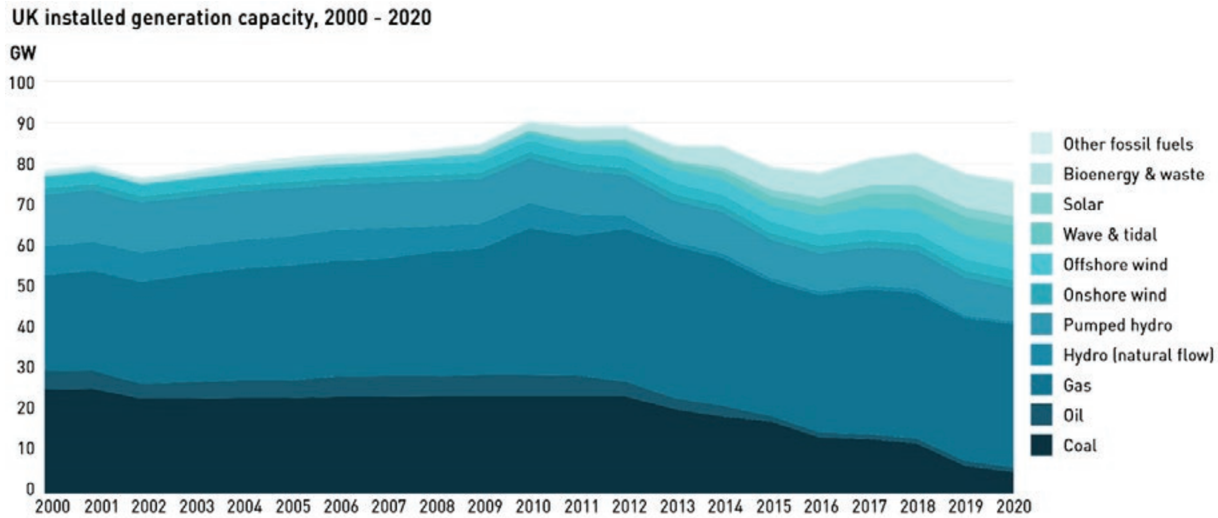
CCGT capacity grew almost threefold between 1996 and 2013, from 12.7 GW to 34.9 GW. As the amount of renewable generation has increased, less efficient CCGTs have been pushed out of the merit order and closed. Several power stations also converted from combined to open cycle operation.

Nuclear capacity has steadily declined with the closure of aging power stations – the last nuclear plant to open was Sizewell B in 1995, with an expected 40-year life. Dungeness B closed in 2021 and Hunterston B at the beginning of 2022, while Hinkley Point B will close in the summer of 2022. Hartlepool and Heysham 1 are set to close in 2024, and EDF recently announced it was bringing the expected closure dates of the two remaining nuclear stations, Heysham 2 and Torness, forward from 2030 to 2028. Hinkley Point C is set to open in mid-2026.

Renewable generation capacity has seen a significant increase, with installed capacity increasing by roughly 18.5 times between 1996 and 2018. Onshore and offshore wind, and solar PV are the main new sources of renewable capacity, supported by subsidy schemes. By the end of 2020, there was 47.8 GW of renewable capacity (22.4 GW on a de-rated basis).

The use of coal in electricity generation declined dramatically between 1980 and 2000, reflecting a decline in domestic coal production. The 1990s were characterised by the “dash for gas”, The use of natural gas for generating electricity had actually banned by EC Directive 75/404/EEC which passed in 1975. But in the 1980s, the Government identified a loophole that allowed the UK’s first Combined Cycle Gas Turbine power station to be developed in the late 1980s, and it opened in November 1991, just eight months after the EC repealed its gas prohibition directive. The early 2000s saw subsidised wind and solar generation in particular beginning to be developed at scale. However, the trajectories of these changes were not smooth.

Figure 7: Installed generation capacity by fuel, 2000-2020



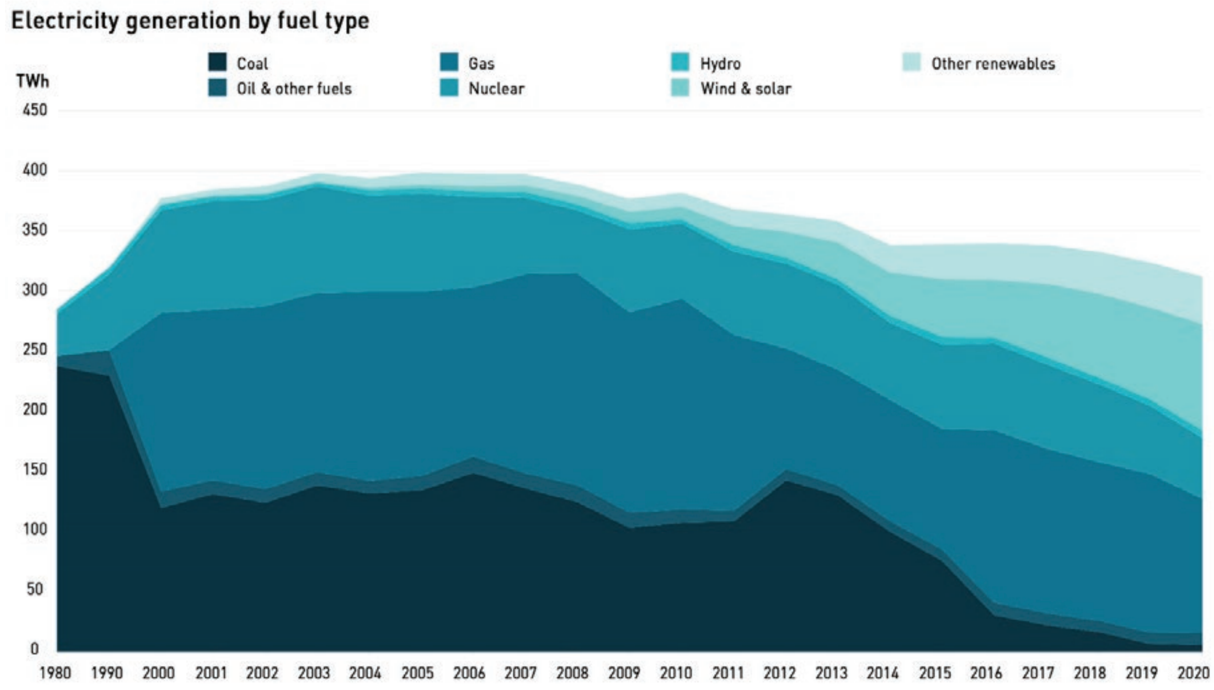
Source: Digest of UK Energy Statistics, 2020

Coal recorded its highest output for ten years in 2006 as nuclear station availability was reduced and gas prices were high. Coal use then trended downwards until 2010 when higher winter electricity demand resulted in an increase from coal, then rose further in 2012, again in response to high gas prices. Subsequently, electricity supply from coal has fallen each year due to plant closures and conversions, although it still forms an important part of the winter generation mix, particularly when wind output is low. By law, all coal plants must close by the end of October 2024.

Gas-fired generation rose significantly between 1990 and 2008 but has subsequently fluctuated with a large increase in 2016 but decreases in 2017 and 2018. Inefficient gas plant has been pushed out of the merit order by renewable generation, but gas continues to form the largest single component of the generation mix and is typically the marginal source of generation, setting wholesale electricity prices.

Supply from nuclear grew to a peak in 1998 before falling back, particularly during 2006 to 2008, as station closures and maintenance outages reduced supply, but recovered in 2009 before falling in 2010 due to further outages. The nuclear fleet is now aging rapidly, and all but one of the remaining nuclear power stations are due to close by 2028. One new large-scale nuclear plant is under construction – Hinkley Point C – which is scheduled to open at the end of June 2026.

Figure 8: UK electricity generation by fuel type, 1980 - 2020



Source: UK Energy in Brief, 2021

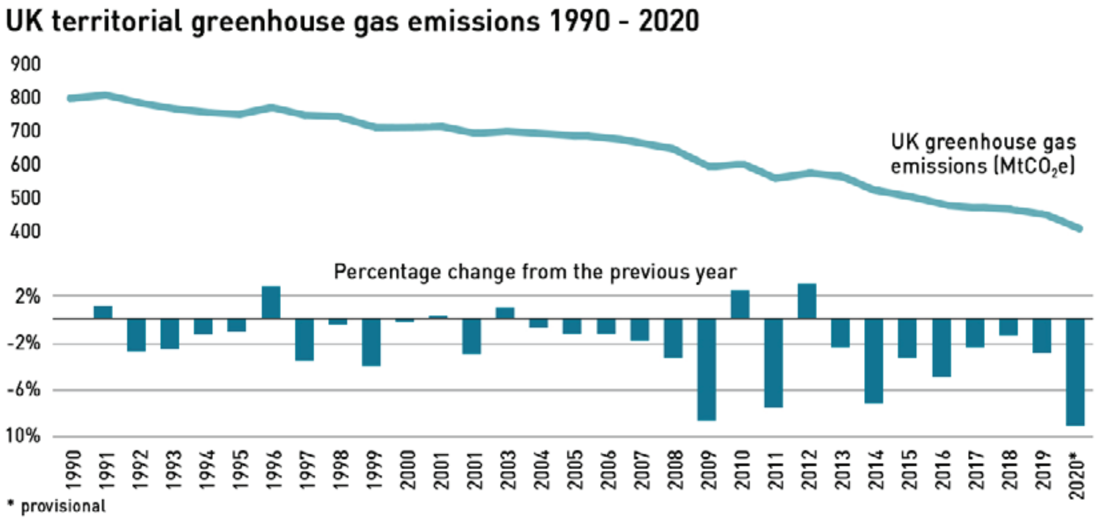
Renewable generation from wind and solar has followed an upward trend since 2000 as capacity increased each year. Subsidy schemes continue to support the development of large-scale renewable generation, with annual output varying both with the addition of new capacity, and the weather conditions. Other renewable generation includes wood-pellet biomass, primarily the large Drax power station, four of whose six boilers have been converted from coal to biomass, with an annual output of 14 TWh.

Total electricity supplied rose continuously from 1997 to reach a peak in 2005. It has subsequently fallen, reflecting lower demand due to energy efficiency, economic and weather factors, with 2018 supply 13% lower than that in 2005.

There has been a significant reduction in UK territorial greenhouse gas emissions[11] since 1990. This has been driven by two main trends: a decline in industrial activity and manufacturing as the economy became more services-oriented, and a shift in the electricity generation mix from a heavy dependence on coal to one dominated by gas and low carbon generation (renewables and nuclear) (**Finding 1**).

11 Territorial emissions are those emitted within the geographical territory, which excludes the emissions relating to imported goods, but includes emissions from the manufacture of goods which are exported.

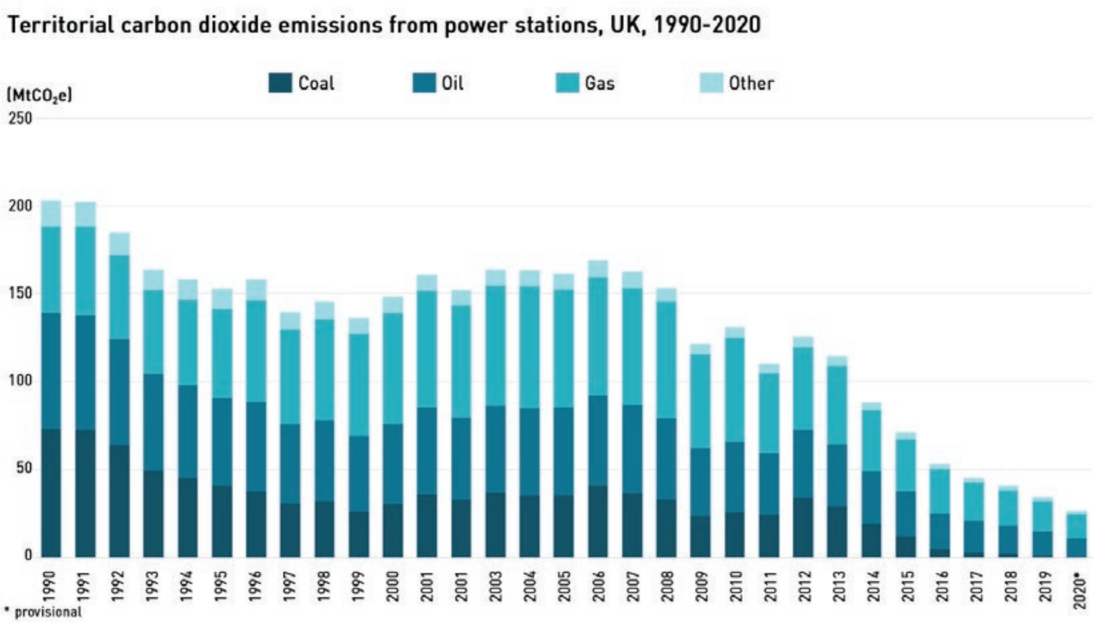
Figure 9: UK territorial greenhouse gas emissions, 1990 - 2020



Source: 2020 UK greenhouse gas emissions, provisional figures, Office for National Statistics

In 2020, carbon dioxide emissions from power stations, at 50.1 Mt, accounted for 15.4% of all carbon dioxide emissions. Carbon dioxide emissions from power stations were 75.3% lower in 2020 than in 1990, despite electricity consumption being around 1% higher in 2020 than in 1990. In 2020 coal made up 2.6% of fuel used for electricity generation, compared to 65.3% in 1990. Renewable generation and nuclear accounted for 56.3% of fuel used for electricity generation in 2020, up from 22.2% in 1990.

Figure 10: Territorial carbon dioxide emissions from UK power stations, 1990 - 2020

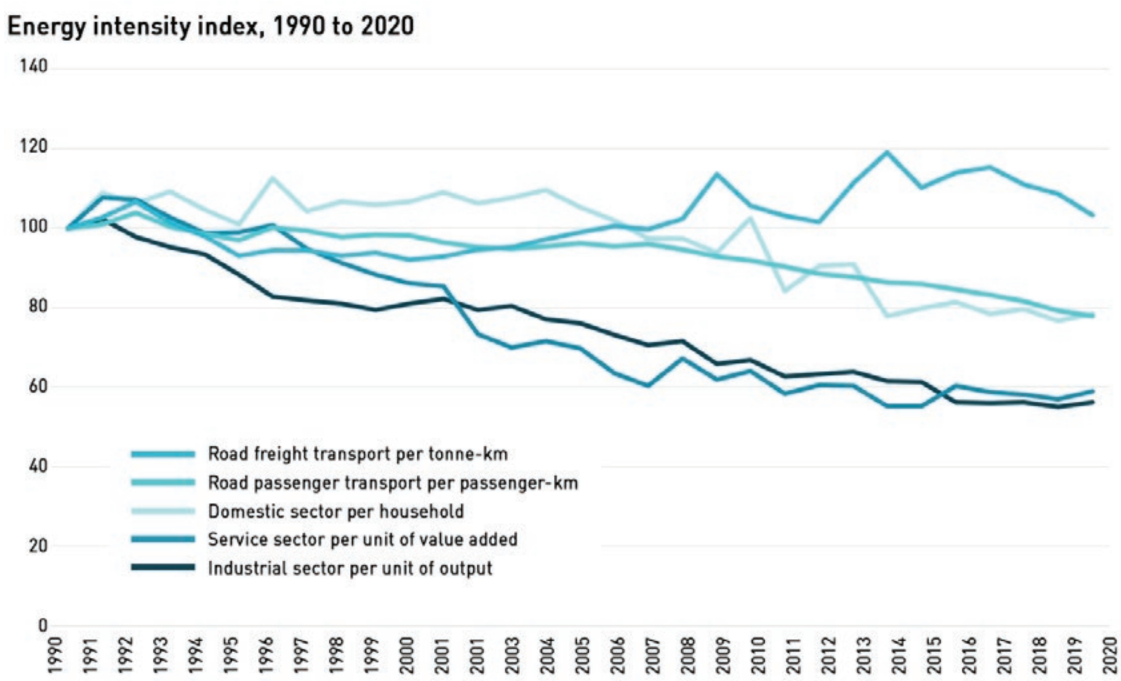


Source: 2020 UK greenhouse gas emissions, provisional figures, Office for National Statistics

Energy consumption per unit of output, known as energy intensity, gives a broad indication of how efficiently energy is being used. Changes in energy intensity can occur due to process change, technological change and structural change (in the case of industry and the service sector) as well as changes in efficiency.

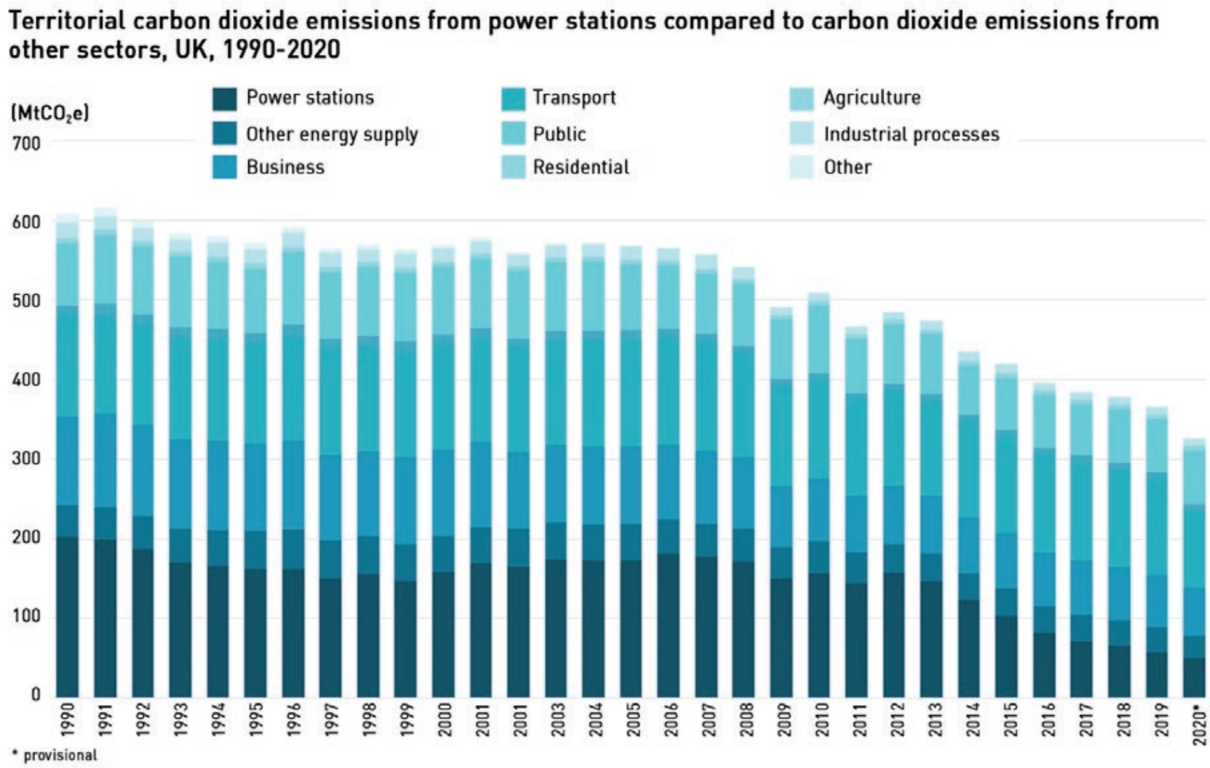
The largest falls in energy intensity over the past thirty years have been in the industrial sector primarily due to structural change in the period before 2000, and in the service sector due to general energy efficiency improvements. In the domestic sector there has been a general downward trend in domestic consumption since 2005, also driven by improvements in energy efficiency.

Figure 11: Energy intensity index, 1990 - 2020



Source: UK Energy in Brief 2021, Office for National Statistics

Figure 12: Territorial carbon dioxide emissions from UK power stations versus emissions from other sectors, 1990 - 2020

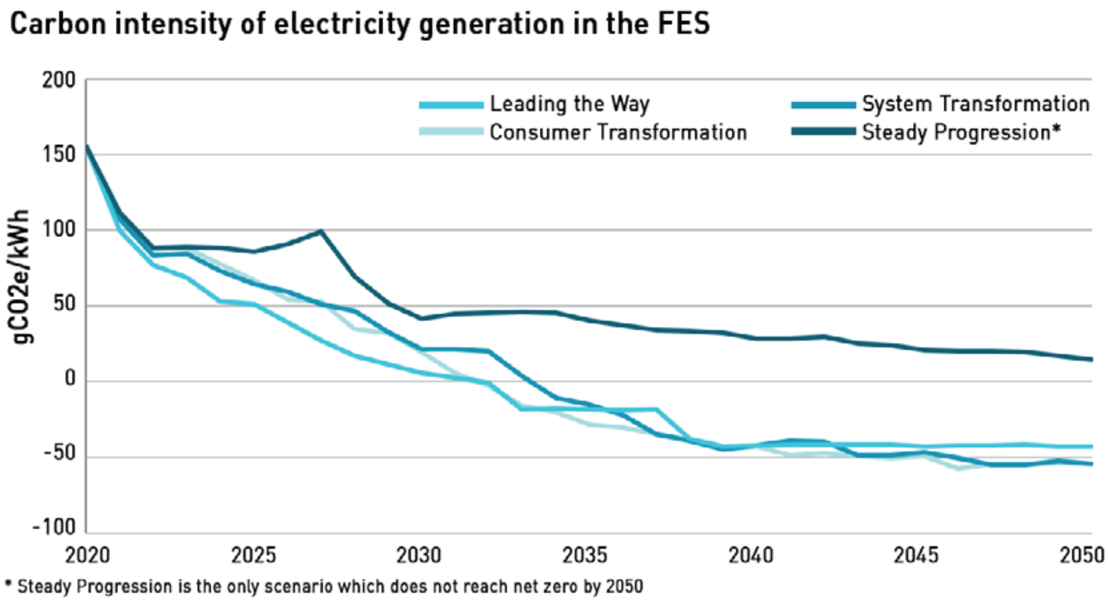


Source: 2020 UK greenhouse gas emissions, provisional figures, Office for National Statistics

Looking ahead, the commissioning of the Hinkley Point C nuclear plant (National Grid ESO, 2021(a)) is expected to contribute to emissions falling faster from the mid 2020s. In the net zero compliant scenarios (all except Steady Progression), gas generation will continue to decline rapidly through the 2020s and 2030s. Under net zero compliant scenarios, the first bioenergy plants with carbon capture and storage ("BECCS") would be commissioned in the late 2020s, delivering negative emissions, and playing an important role in offsetting low residual emissions from electricity generation and other sectors.

However, there are ongoing debates about the sustainability of wood-pellet biomass which is currently the main source of biomass generation, given both the supply chain emissions and power-station emissions that are higher than those from coal. The Government plans to develop a biomass business model that requires sustainably sourced biomass. To date there are no biomass plants fitted with CCS and the very small number of coal CCS plants have failed to capture the expected levels of emissions and have been uneconomic to run. BECCS is therefore highly speculative.

Figure 13: Electricity sector carbon intensity under the Future Energy Scenarios including negative emissions from BECCS



Source: National Grid ESO, Future Energy Scenarios 2021

2.6 Demand-side response and the emergence of the "prosumer"

In its Future Energy Scenarios 2021 (National Grid ESO, 2021 (a)), National Grid ESO expects demand-side flexibility to exceed supply-side flexibility by 2025, with up to 43 GW of electricity storage across its scenarios in 2050, compared to 3.5 GW today, 44 GW of demand side response, compared to 6 GW today and 58 GW of electrolysis from close to zero today.

Two of the four scenarios have highly engaged consumers, enabling total peak demand to be reduced by over 43% due to demand side response ("DSR"). In the other scenarios, demand side flexibility take-up is lower due to less consumer engagement, however they still see over 20% total peak demand reduction from DSR. The question is whether these assumptions are realistic, and if so, how the benefits of domestic DSR can be captured in practice.

Research from CREDS (Crawley, 2021) showed that low-income households struggle to shift demand since they lack flexible energy assets, and there are issues around fairness when the evening peak coincides with dinner time, and the time that young children go to bed.

There are also issues around who is responsible for shifting demand: householders or external parties. Low-income households are not only less likely to own flexible assets, but also face other barriers to engagement such as digital exclusion, low levels of literacy and numeracy, and higher levels of disability. However, reliance on third parties requires trust, and regulatory frameworks that protect the vulnerable. One trial which used externally controlled technology to shift heating demand achieved a high demand response, as many households did not understand how their heating worked or even that they were in a demand response trial. But in a minority of homes, the occupants took back control by disconnecting the communications technology to opt out of shifting. High levels of shifting relied on occupants not getting involved, and when they did, this decreased the demand response.

In Winter 2022-23, in response to concerns over capacity margins, National Grid ESO introduced a new demand-side response service including households for the first time. Known as the Demand Flexibility Service (DFS), the scheme was expected to secure up to 2 GW of demand reduction from both homes and businesses (there are also other demand-side schemes open to business consumers). Consumers receive at least £3 /kWh for any reductions in consumption during the times the service is activated.

Various trials were conducted in the early parts of the winter, and at the time of writing (early February 2023, the scheme has been activated twice although doubts have been raised as to whether the activation of the service was genuinely operationally necessary (Porter 2023).

The scheme has had a number of limitations:

- it was only available to households with a functional smart meter (13 million households have a traditional non-smart meter, while 1.7 million households have smart meters that do not work in smart mode. 14 million households have suitable smart meters;
- not all suppliers are participating in the scheme so not all consumers with a suitable meter are able to take part;
- the scheme is notified at the day ahead meaning that if the supply balance improved in the day leading up to delivery other generation would need to be turned down. In practice the DFS has been activated alongside instructions to warm the coal plants in the Winter Coal Contingency scheme, but so far the coal plants have not been required to generate after warming, which is likely inefficient given the costs of warming;
- there is anecdotal evidence of some households taking extreme measures to secure DFS payments, for example sitting in their cars instead of in the house, sitting in bed in the dark with the heating turned off, and turning off appliances such as fridges and freezers which poses a food safety risk;
- many DFS participants are already reducing consumption in response to high prices, meaning that they have limited scope for further reductions when the scheme is activated. Some have reported receiving payments as low as 30 pence (just under C$ 0,50) for an hour of demand reduction (this compares with the current government subsidised electricity price for households of 33.2 p/kWh).

3 History of environmental energy legislation in GB

3.1 Key energy legislation

The legislative process in the UK is broadly the same for all types of legislation, including energy legislation. The Government produces draft Bills which may involve the issuance of Green and White Papers for public consultation.[12] It is typical for Ofgem, National Grid, network operators, energy suppliers, generators, energy industry associations, other energy market participants, charities, and private individuals to participate in these consultations. Following the consultation, which may also involve consideration by House of Commons or House of Lords Committees, the Bill will be presented to Parliament for debate. For a Bill to become law, i.e., an Act of Parliament, it must be passed by both Houses of Parliament.

The legislative framework for the decarbonisation of the GB energy market is described below:

(i) *Utilities Act 2000* – required electricity suppliers to supply a certain proportion of their total sales in the UK from electricity generated from renewable sources.

(ii) The *Energy Act 2008* – established a renewables obligation for generating electricity from renewable sources and made provisions for smart meters.

(iii) *Climate Change Act 2008* – required that the net UK carbon account for all six Kyoto greenhouse gases for the year 2050 be at least 100% lower than the 1990 baseline. An independent Committee on Climate Change was created to provide advice to the UK Government on these targets and related policies. The Act established long-term statutory targets for the UK to decarbonise by reducing its greenhouse gas emissions.

(iv) The *Energy Act 2010* – required the Government to prepare reports on the progress made on the decarbonisation of electricity generation and to create schemes for energy suppliers to give benefits to customers to reduce fuel poverty.

(v) EU Directive 2010/75/EU on industrial emissions (Industrial Emissions Directive) – required a reduction in emissions from industrial production using a polluter pays approach to assign the cost of plant updates.

(vi) Promotion of the Use of Energy from Renewables Sources Regulations 2011 (SI 2011/243) – required the Government to ensure that renewable energy comprised 15% of the UK's total energy mix by 2020.

(vii) The *Energy Act 2013* – the principal legislation relating to renewables, implementing the UK government's Electricity Market Reform ("EMR") plans.

The *Climate Change Act 2008* was the most significant piece of climate legislation. It had been preceded by a Climate Change Bill, drafted by lobby group Friends of the Earth, and presented as a Private Member's Bill (i.e., not part of the Government's legislative programme) in 2005. Passage of the Bill was interrupted by the 2005 General Election, but a new version was brought forward in the new Parliament after more than 400 MPs signed an Early Day Motion calling for such a Bill.[13] This was in response to concerns from environmental groups and MPs that the UK was on target to miss its Kyoto Protocol commitments.

The UK Government took the lead in focusing political and economic attention on the state of the climate, in particular during its presidency of the European Union in 2005 and the G8 (Lorenzonia, 2007), and progress on emissions reductions was largely a result of the move from coal to gas in the electricity sector. The levels of individual behavioural change required to meet climate targets was identified as lacking prior to the passing of the *Climate Change Act*, and continues to be a barrier to progress (see Section 5.7).

12 Although not formal definitions, Green Papers usually put forward ideas for future government policy that are open to public discussion and consultation. White Papers generally state more definite intentions for government policy.

13 Private Members' bills are public bills introduced by MPs and Lords who are not government ministers. An Early Day Motion is a motion submitted for debate in the House of Commons for which no day has been fixed.

3.2 Electricity Market Reform

The Government set out its intention to reform the electricity market in the Electricity Market Reform ("EMR") White Paper in July 2011 and the EMR Technical Update in December 2011. The EMR provisions passed into law in the *Energy Act 2013*, which put in place measures to attract the £110 billion of investment the Government believed would be needed to replace retiring generating capacity and upgrade the electricity grid by 2020, and to cope with the expected increase in electricity demand from electrification. The key elements of EMR included:

(i) a mechanism to support investment in low-carbon generation: the Feed-in-Tariffs ("FiT") with Contracts for Difference ("CfD");

(ii) a mechanism to support security of supply, if needed, in the form of a Capacity Market; and

(iii) the institutional arrangements to support these reforms.

These mechanisms would be supported by:

(i) the Carbon Price Floor – a tax to underpin the carbon price in the EU ETS;

(ii) an Emissions Performance Standard – a regulatory measure to limit emissions from new fossil fuel power stations at 450g CO2/kWh to ensure that no new coal-fired power stations are built without CCS, and to facilitate necessary short-term investment in gas;

(iii) the Electricity Demand Reduction Pilot – a study to explore the viability of including energy efficiency measures in the Capacity Market; and

(iv) measures to support market liquidity and access to market for independent generators.

The Electricity Demand Reduction Pilot found that energy efficiency measures would struggle to compete in the Capacity Market and so far, no such schemes have been progressed.

The objectives of EMR were to ensure a secure electricity supply by providing a diverse range of energy sources, including renewables, nuclear, carbon capture and storage equipped plant, unabated gas and demand-side approaches; and ensuring enough reliable capacity was available to minimise the risk of supply shortages. EMR was also intended to attract sufficient investment in sustainable low-carbon technologies to meet EU 2020 renewables targets and the UK's longer-term target at the time to reduce carbon emissions by at least 80% of 1990 levels by 2050.

Finally, EMR was intended to maximise benefits and minimise the costs to the economy as a whole and to taxpayers and consumers, maintaining affordable electricity bills while delivering the investment needed. EMR was designed to minimise costs compared to previous policies by using market dynamics and competition. The need for Government intervention was to decline over time. These radical plans were supported by the political Left, who viewed it as a move a way from the liberalisation of privatisation under the Thatcher Government. The political Right was more sceptical, concerned over the level of state intervention in the market.

3.3 Future legislation

In December 2020, the Government issued an Energy White Paper entitled “Powering our Net Zero Future”, which set out how the Government intends to meet its targets to reduce UK greenhouse gas emissions. The White Paper builds on the “Ten Point Plan for a Green Industrial Revolution” published in November 2020. Key features of the Energy White Paper and Ten Point Plan include:

(i) targeting 40 GW of installed offshore wind capacity by 2030 through £20 billion of private investment;

(ii) investing £1 billion in the energy innovation programme to develop future technologies such as green hydrogen, with the aim of 5 GW of low-carbon production capacity by 2030;

(iii) developing a biomass strategy, particularly biomass with carbon capture and storage;

(iv) aiming to bring at least one large-scale nuclear project to the point of final investment decision by the end of the current Parliament;

(v) increasing the proportion of sustainable biomethane in the gas grid; and

(vi) increasing the funding available to study the use of hydrogen in homes and consulting on the role of “hydrogen-ready” appliances.

The White Paper formed the basis for a new Draft National Policy Statement for Energy in 2022, however this was not finalised and appears to have been abandoned with the various changes in Government in 2022. There is a commitment to issue a new National Policy Statement for Energy, following a number of new policy initiatives which were announced during the year.

At the time of writing (February 2023) a new Energy Bill, sponsored by BEIS (now Department for Energy Security and Net Zero) is progressing through Parliament (UK Parliament, 2023). This Bill includes provisions relating to energy production and security and the regulation of the energy market, the licensing of carbon dioxide transport and storage; commercial arrangements for industrial carbon capture and storage and for hydrogen production; new technologies, the introduction of low-carbon heat schemes and hydrogen grid trials; the creation of an Independent System Operator and Planner; a new governance framework for gas and electricity industry codes; regulation of heat networks; regulation of smart appliances and load control; powers to review the energy performance of premises; powers relating to energy savings opportunity schemes; new powers to ensure the resilience of the core fuel sector; new regulations relating to offshore energy production, including environmental protection, licensing and decommissioning; revised powers relating to the civil nuclear sector, including the Civil Nuclear Constabulary and pensions.

3.4 The deployment of renewable generation in Great Britain

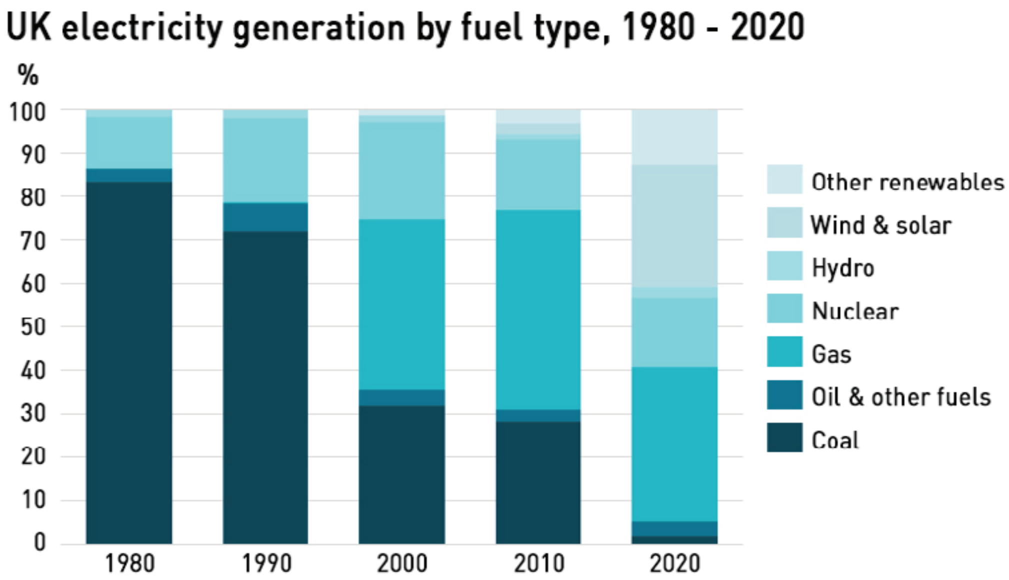
In 1980, 83% of electricity generation came from coal, 12% from nuclear and the rest from oil and hydro. By 2020, coal and oil[14] together represented 5% of generation, gas was 36%, nuclear and hydro 18% and renewables 41%, of which wind and solar together were 28%.

With the rise of intermittent generation and the decline of dispatchable generation, steps needed to be taken to ensure there is sufficient generation available to meet demand when weather-dependent generation is unavailable. As a result, almost every form of generation in Britain is entitled to some form of subsidy: renewable generation benefits from legacy RO and FiT schemes as well as the CfD,[15] while fossil-fuel and nuclear generation are eligible to participate in the Capacity Market (**Finding 2**).

14 There are no oil-fired transmission-connected power stations, but there are small diesel generators connected at the distribution level, many of which were developed after the introduction of the Capacity Market. As the Capacity Market was designed to be technology-neutral, it favoured generation with low start costs irrespective of emissions levels.

15 The RO (Renewables Obligation) was the first major subsidy scheme aimed at large renewable generation. The scheme closed to new projects in 2017 with contracts lasting until 2037 and was replaced by the CfD (Contracts for Difference) scheme. The FiT (Feed-in-Tariff) supported small-scale renewables. This scheme has also been closed to new projects and has been replaced by a system that simply pays small renewable generators for the electricity they export to the grid, rather than total generation.

Figure 14: Share of generation by fuel type, 1980-2020



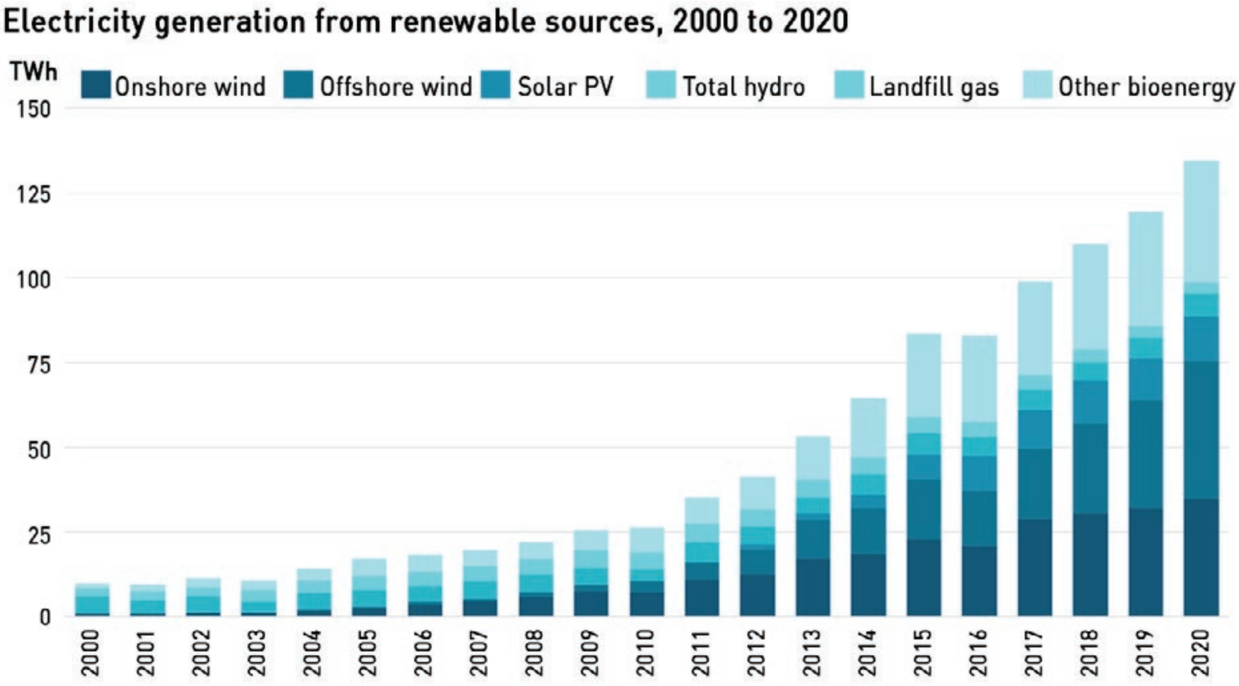
Source: UK Energy in Brief 2021, Office for National Statistics

While favourable weather conditions along with increased capacity saw higher renewable output in 2020, particularly in offshore wind, which generated 27% more electricity in 2020 than in 2019, the weather in 2021 told a different story, with much lower wind conditions. September in particular saw a sustained period of low wind across Northern Europe which limited the ability of imports to fill the gap.

Prior to 2011, solar PV formed a very small part of the renewable energy mix at just 1.0% of total capacity. Between 2011 and 2017 it increased significantly with capacity added during that period accounting for 87% of the current installed capacity. Although growth has slowed since 2017, largely due to the closure of the Feed-in-Tariff in April 2019, solar PV's share of the renewable mix was 28% in 2020. Larger-scale solar projects are increasingly being proposed on greenfield rural sites, which attracts significant local opposition, which may impede its growth.

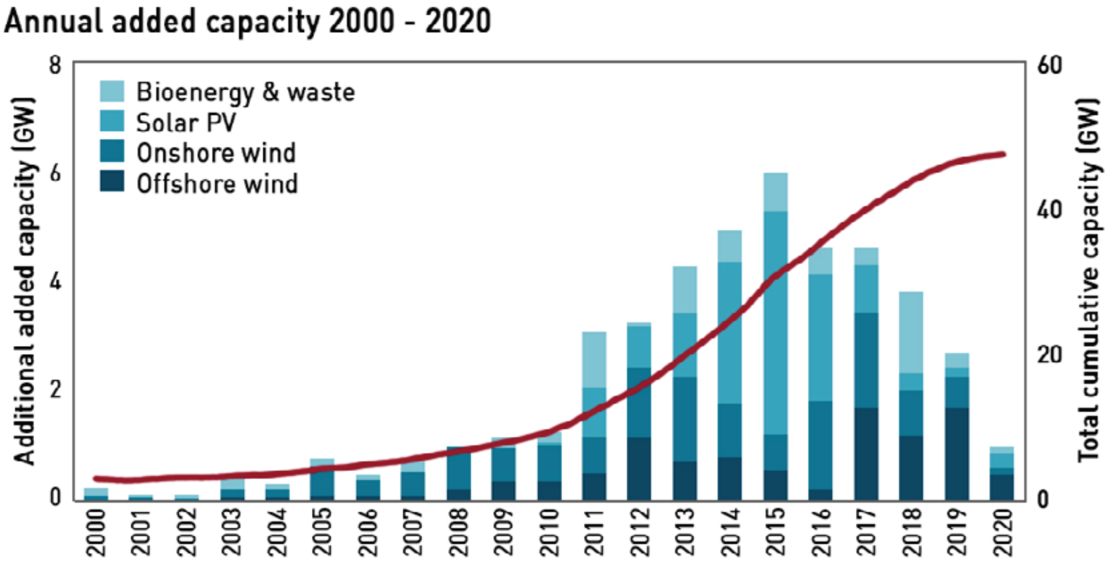
Growth in new wind generation has been more stable – particularly onshore wind – although this has slowed significantly over recent years with just 0.1 GW added in 2020. Offshore wind capacity has grown more quickly in recent years with almost half being installed since 2016. Wind now accounts for over half total installed capacity. Despite the slowdown in new capacity, the overall picture of increasing generation since 2000 remains positive with total generation in 2020 at 134.6 TWh, 13% higher than in 2019.

Figure 15: Renewable generation by technology, 2000-2020



Source: Digest of UK Energy Statistics, 2020

Figure 16: New renewable generation capacity added each year, 2000-2020



Source: Digest of UK Energy Statistics Annual data for UK, 2020

Hydro is a mature technology with generation fluctuating year on year in line with rainfall. In contrast, solar PV only began to emerge from 2012 incentivised by the Feed in Tariff, increasing its share of renewable generation from 3.3% in 2012 to 9.8% in 2020. Bioenergy saw rapid growth from 2012 as several large coal power stations converted to plant biomass. Generation from biogas has been fairly stable initially with declining generation from landfill and sewage gas being offset by increasing amounts of anaerobic digestion.

3.5 The cost of de-carbonising the GB energy mix

Currently, almost every form of generation in the GB market is entitled to some form of subsidy. Renewable generation benefits from legacy RO and FiT schemes as well as the replacement CfD scheme, while fossil-fuel and nuclear generation is eligible to participate in the Capacity Market. The costs of these schemes are met by electricity consumers since they are added on to electricity bills. In his 2017 Government-commissioned report into the cost of energy in Britain, Dieter Helm (2017) highlighted the complexity of various market interventions, that "interact with each other in ways that stretch any policy analysis or cost–benefit test". He identified 17 separate agencies and organisations running these policies. Helm was of the view that the costs of decarbonisation, as forecast by the CCC were excessive:

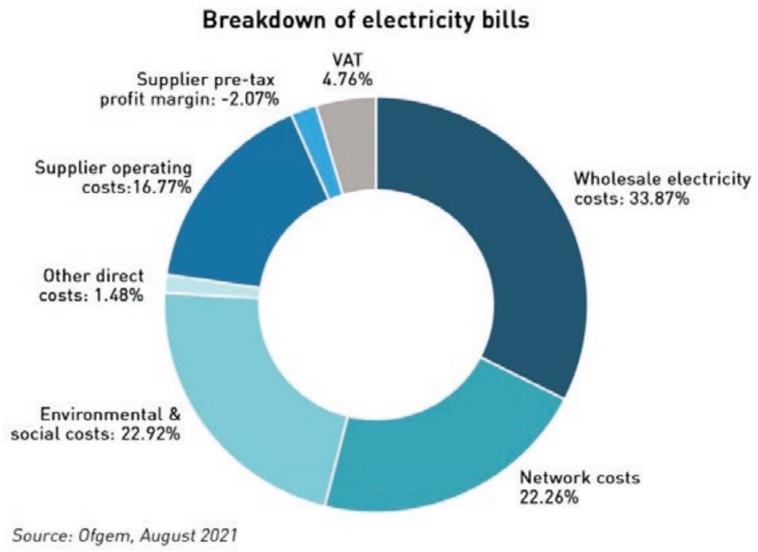
> "...the sheer scale of the numbers gives an indication of how expensive the ROCs and EMR contracts have been so far. It is hard to imagine that more carbon reductions could not have been achieved for a total cost which will exceed £100 billion by 2030 – or that the same could not have been achieved for significantly less. Second, the numbers are around 90% already determined. Falling costs for future renewables will not result in lower legacy costs. Third, the falling costs of intermittency will not feed through to a lower LCF because these costs are excluded." (**Finding 3**).

A critical report by the National Audit Office (NAO, 2016) found that the Government was very close to the cost cap imposed by the Levy Control Framework, which was designed to limit the costs of environmental levies to consumers and formally established in 2012. The Framework set a cap on the forecast costs of certain policies funded through levies on energy suppliers in response to concerns from industry, consumer groups and HM Treasury that the impact of environmental policies on consumer bills should be minimised. It required the Department (responsible for energy and climate, which has had several different identities since 2000) to take early action to reduce costs if forecasts exceeded the cap, with urgent action required if they exceeded a 20% headroom above the cap.

Initially, the Framework was intended to control the impact of all levy-funded energy schemes but, in 2012 the Government decided that it would only cap the costs of policies supporting low-carbon generation, excluding other schemes, such as the Capacity Market, despite the associated costs to consumers being substantial. This move was not well received, but it provided the Government with additional scope within the cap to fund its environmental commitments.

In response to rising costs, and various projections that indicated the cap would be reached well before the 2020/21 target date, the Government determined that the Framework needed to be updated, instituting the Control for Low Carbon Levies in the November 2017 Budget. While there would no longer be a cap or budget for low carbon levies, the Government committed that no new low carbon electricity levies would be implemented until the total burden of these costs was forecast to fall in real terms over a sustained period (not expected to be before 2025). However, new levies could still be considered where they were forecast to have a net reduction effect on bills and were consistent with the Government's energy strategy. Since then, there has been little transparency on the projected costs to consumers of the various subsidy schemes.

Figure 17: Breakdown of electricity bills, August 2021



Source: Ofgem

Current wholesale price rises will push the retail price cap significantly higher at its next revision in April, and the Government is under pressure from consumer groups, NGOs and politicians across the political spectrum to take action to support consumers – with calls for both VAT relief and the removal of environmental levies. Heavy industry is also lobbying hard for support as high energy costs combined with high carbon pricing reduce their international competitiveness.

British electricity consumers still face decades of payments under existing low carbon subsidy commitments. For example, consumers will continue to make Renewables Obligation payments until the final contracts expire in 2037. There are currently concerns that recovering these costs through electricity bills makes electricity artificially more expensive than gas, which will deter the electrification of heating. Therefore, the Government has been evaluating alternative approaches such as moving the recovery of these costs to gas bills instead, although if the efforts to reduce gas consumption are successful, this would involve taxing a declining tax base, which would be unsustainable.

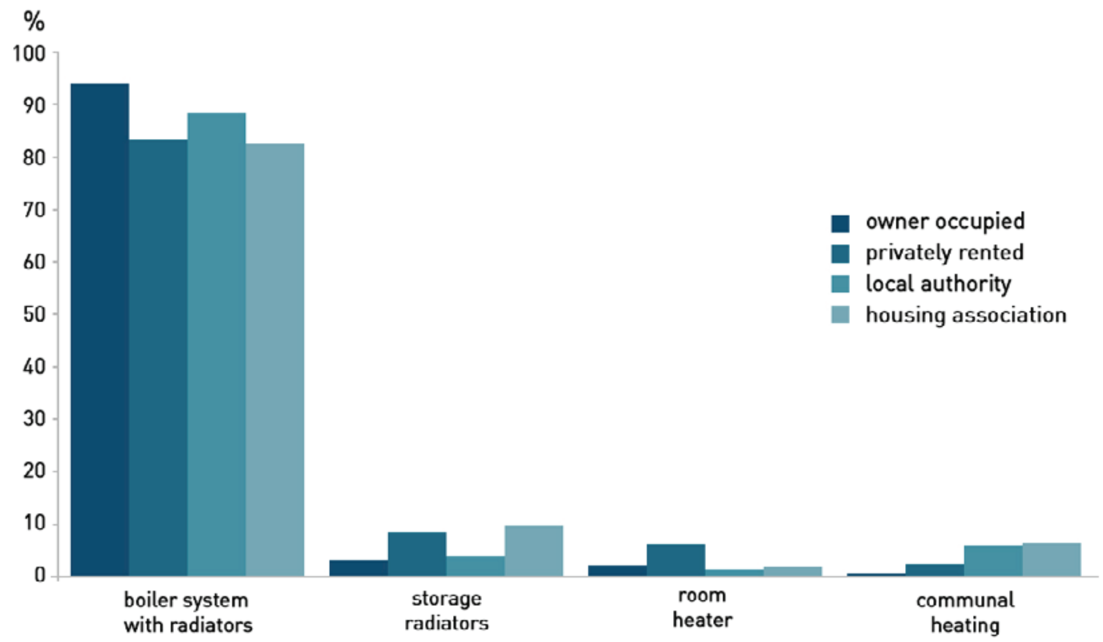
There is also widespread consensus that recovery of environmental subsidies through bills is highly regressive, in that people on low incomes are disproportionally impacted by the costs since they are the least able to control their consumption. The Government had assumed efficiency improvements would more than offset the cost impact of low carbon levies. However, demand reduction strategies such as improved insulation, installation of renewable generation, or acquisition of more efficient appliances typically require up-front investment which is beyond the reach of those on low incomes. Low-income households are also more likely to live in rented accommodation, and as such are unable to make the necessary home improvements.

3.6 De-carbonising the gas market

Currently natural gas for space and water heating (and to a lesser extent, cooking) amounts to 65% of residential energy demand in GB, with residential demand accounting for around 480 TWh, or 35% of GB total demand in 2020. 86% of British households make use of gas central heating (Ministry of Housing, Communities & Local Government 2021(a)).

There have been efforts to incentivise the use of renewable heating technologies for the past decade: the non-domestic RHI launched in November 2011 with a domestic version launching in April 2014 to help businesses and homes to meet the cost of installing renewable heat technologies. The non-domestic scheme closed to new entrants in March 2021, while the domestic scheme is set to close at the end of March 2022. In 2018 both the National Audit Office ("NAO") and Public Accounts Committee ("PAC") investigated the RHI and found issues with the scheme's effectiveness. The NAO (Davies, 2018) found take-up of the scheme was lower than anticipated, would likely only achieve 22% of the number of installations originally planned, and raised doubts about its cost-effectiveness (**Finding 4**).

Figure 18: Most common heating systems, by tenure, 2019



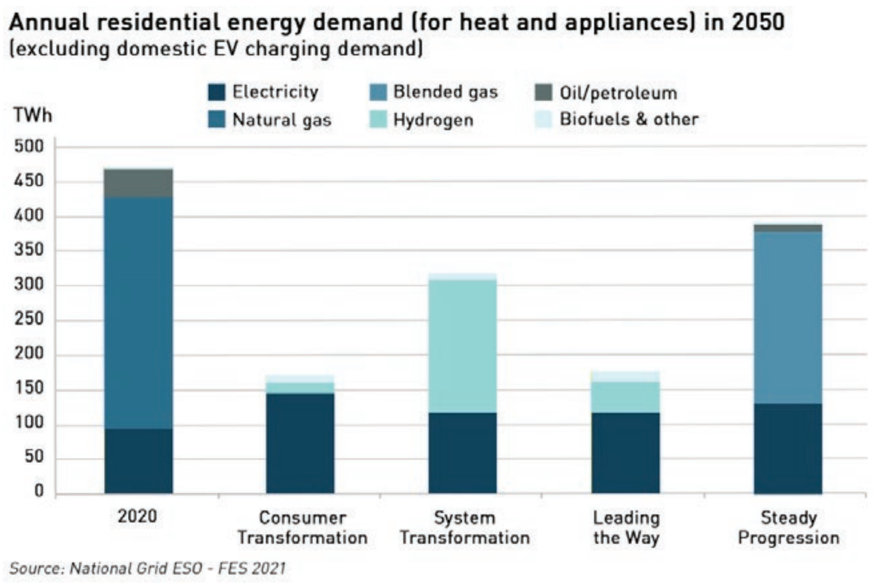
Source: Ministry of Housing, Communities & Local Government 2021

The PAC (Committee of Public Accounts, 2018) said the RHI "does not work for households and businesses unable to pay the high upfront costs of renewable and low-carbon heating equipment". Its report found that the Government's forecasts of uptake were "wildly over-optimistic" – just 60,000 renewable systems were installed under the scheme compared with 6.2 million gas boilers during the period in question. One reason cited for this under-performance was the inconvenience to consumers of installing renewable heating compared with gas and oil boilers.

In November 2021, a new four-year tariff-based scheme was launched – the Green Gas Support Scheme ("GGSS") – to support the injection of biomethane produced via anaerobic digestion into the gas grid. The scheme will help decarbonise Britain's gas supplies by increasing the proportion of "green" gas in the grid. During peak years of production, the biomethane plants incentivised by the GGSS are expected to produce enough green gas to heat around 200,000 homes and contribute 3.7 million tons of CO_2 equivalent of carbon savings over Carbon Budgets 4 and 5,[16] and 8.2 million tons of CO_2 equivalent of carbon savings over its lifetime. The scheme only supports biomethane produced by anaerobic digestion and does not extend to other green gasses or hydrogen, although it may be expanded in the future. The Government is also considering its hydrogen strategy.[17]

The Government's Future Homes Standard (Ministry of Housing, Communities & Local Government 2021(b)) requires homes built from 2025 to have low carbon heating (the full specification of which is expected in 2023), and the Government has committed to installing 600,000 heat pumps per year by 2028 in homes across England – compared to around 30,000 heat pumps currently installed. This is to be supported by grants of up to £5,000 which cover roughly half of the value of a new heat pump, excluding the costs of upgrading home insulation which is generally required to deliver desired comfort levels. The Government has signalled an intention to ban the installation of new gas (i.e., methane) boilers by 2035, encouraging conventional boilers to be replaced by low carbon alternatives as part of their natural replacement cycle.

Figure 19: Annual residential energy demand (for heat and appliances) in 2050 (excluding EV charging demand)



Source: National Grid ESO – FES 2021

Although there is a common perception that heating will be electrified, National Grid ESO's Future Energy Scenarios anticipate that gas will remain important, although it will be either methane blended with biogases or hydrogen. Demand reduction through improved thermal efficiency is also an important theme.

16 A carbon budget places a restriction on the total amount of greenhouse gases the UK can emit over a 5-year period.
17 The Government issued a Hydrogen Strategy document in 2021 outlining some of the facets that a hydrogen strategy should involve, with the intention of finalising the Hydrogen Business Model in 2022.

3.7 The role of carbon pricing

To meet the UK's emission reduction targets under the Kyoto Protocol, additional financial incentives were needed to reduce energy consumption and hence emissions, but this had to be done in a way which did not increase the number of households in fuel poverty (where more than 10% of household income is spent on energy). Any tax measure needed to be perceived as fair to individual households, avoid taxing transport, be revenue-neutral and have special provisions for energy-intensive industries to avoid loss of international competitiveness. The solution, introduced in 2001, was the Climate Change Levy, a tax on supplies of electricity, gas and solid fuels used by the industrial, commercial, agricultural, and public administration sectors (i.e., this is an energy tax rather than a carbon tax). Large fossil-fuel power stations pay at the Carbon Price Support rate.

Concerns around the competitiveness of British industry meant a discount was required for energy-intensive industries which was initially set at 50% and subsequently increased to 80%. In order to secure environmental benefits from the discounts, these industries had to agree to Climate Change Agreements ("CCAs") requiring them to increase energy efficiency and reduce carbon dioxide emissions. Initially CCAs were linked to the voluntary UK Emissions Trading Scheme ("UK ETS") which ran from 2001 until 2009. From 2005 mandatory participation in the EU Emissions Trading Scheme ("EU ETS") meant adjustments to the CCAs were required.

In April 2013, the Government introduced the Carbon Price Floor ("CPF") to encourage investments in low-carbon technologies, in response to persistently low prices in the EU ETS. The CPF creates a minimum price for carbon and consists of the EU ETS Allowance rate (now the new UK ETS following Brext) and the Carbon Price Support ("CPS") rate. The benefits of the system were set out in the Coalition Government's Carbon Price Floor consultation response published in 2011:

> "Over the long term (2013-2030) a price floor targeting £30 /tCO_2 provides £1.9 billion of net present value benefits. It also achieves the right balance between encouraging investment without undermining the competitiveness of UK industry. The £30 /tCO_2 price floor in 2020 rising to £70 /tCO_2 in 2030 will drive £30-£40 billion of new investment in low-carbon electricity generation. This is equivalent to 7.5 - 9.3 gigawatts (GW) of new capacity."

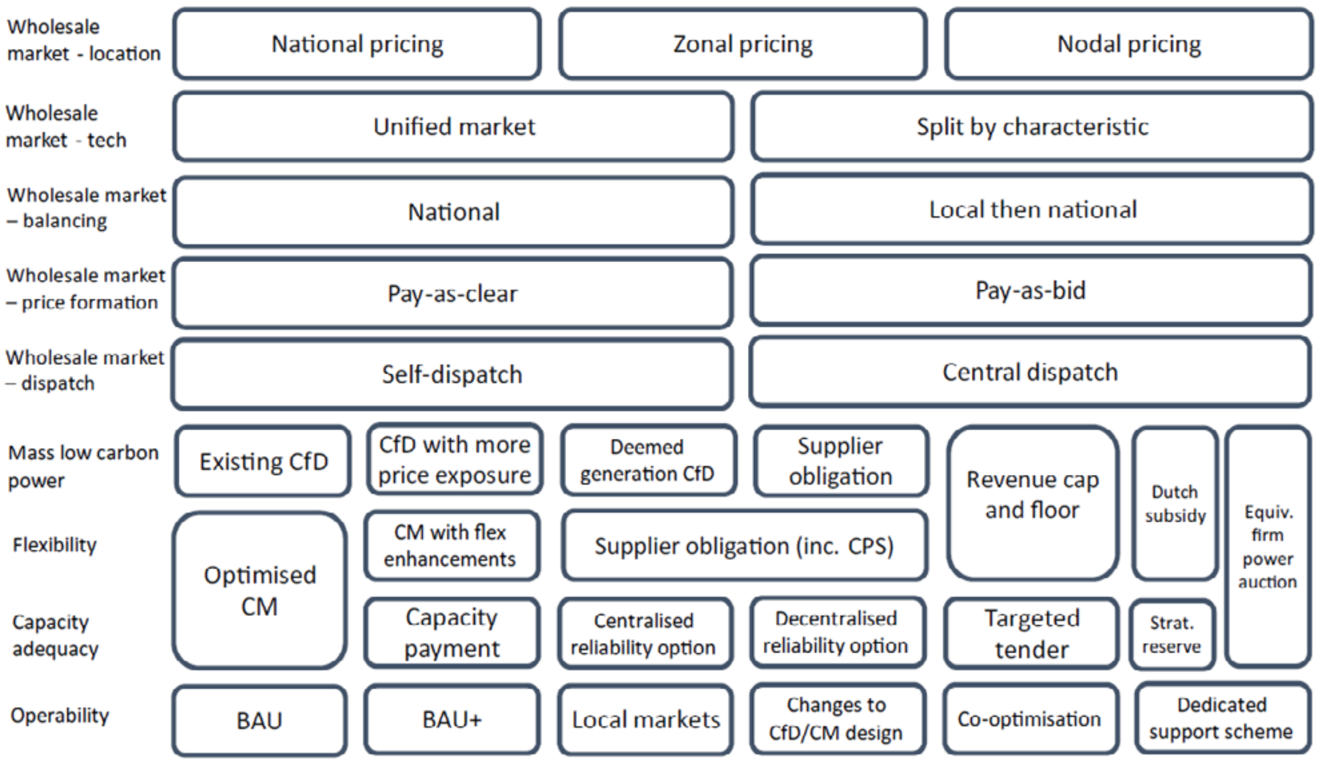
3.8 Review of Electricity Market Arrangements (REMA)

The Government's REMA consultation[18] ran from July through October 2022, with responses currently being evaluated. . This consultation included a wide range of proposals for reforming the electricity system, from the subsidy regimes for renewable generation to changes to market structure and price formation. One of the options under consideration is a move away from a uniform national pricing system to a zonal or even nodal model (Locational Marginal Pricing or LMP). Other proposals in the consultation would involve splitting the market into intermittent renewables and everything else in order to remove the link between gas prices and the cost of renewable generation. The Government believes this would also require a return to central dispatch although a central clearing model could also be used.

There are also discussions around the extent to which Distribution Network Operators should become more involved with system balancing and stability procurement, since the energy transition will also impact the operation of lower voltage networks.

18 https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements

Figure 20: REMA options under consideration



Source: Department for Business, Energy and Industrial Strategy

REMA is exploring major structural changes to the electricity market in GB, and any such changes would take years to design and implement – likely in the region of five to eight years. In the meantime, NG ESO will continue to develop its ancillary services markets for high voltage transmission, and similar markets may begin to emerge at the distribution level.

4 Key challenges for the next phase of the energy transition

4.1 Managing the next phase of the transition will be more complex

The British market is at a key point in its transition. Penetration of renewable generation has grown to a degree that the design and operation of electricity networks needs to evolve to accommodate generation in new locations and to manage the growing impact of intermittency, while at the same time, legally binding net-zero targets are driving the electrification of heating and transport (**Finding 1**).

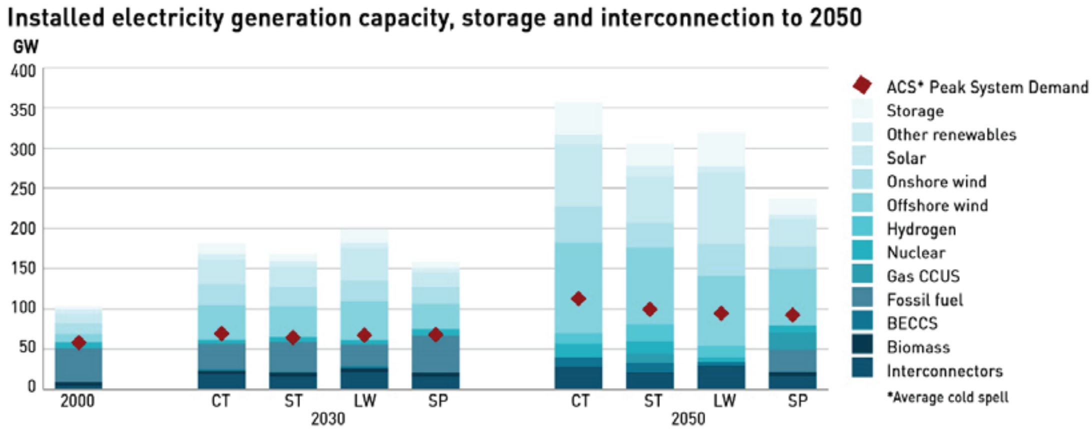
4.2 How will demand for gas and electricity evolve in response to net zero policies?

There is an expectation that electricity demand will increase significantly (National Grid ESO, 2021(a)) in response to net zero policies which will either mandate or incentivise a switch away from more carbon-intensive fuels. Increased electricity peak demands will require more generation capacity, particularly renewables, as well as flexible technologies and demand side response. Investments in network capacity will be needed to connect these assets, and to ensure local networks allow most premises to operate electric vehicle ("EV") charging and heat pumps (many domestic connections currently would not allow for both due to lack of connection capacity).

> "Total installed capacity will need to increase at least three-fold by 2050 in the net zero scenarios, with more capacity needed in the scenarios with higher levels of societal change. These scenarios typically have higher levels of electrification, leading to increased annual and peak demands and greater need for renewable generation capacity,"
>
> – National Grid ESO

However, concerns[19] over the competitiveness of energy intensive industries, costs to consumers and the risk of carbon leakage led to the CPF being capped in 2016 at £18 /tCO_2. This price freeze has been extended several times and will now remain in place until at least 2022/23. Concerns over carbon leakage arise because the UK's emissions reductions targets are territorial, i.e., relate to carbon emitted within the UK's borders, excluding emissions from imported goods. The EU is planning to introduce a carbon border adjustment mechanism based on a system of certificates to cover the embedded emissions in products being imported into the EU.[20] The UK is considering a similar scheme.

Figure 21: Installed electricity generation capacity, storage and interconnection



Source: National Grid ESO – FES 2021

19 Heavy industry and consumer groups both lobbied for costs to be contained.
20 Transitional arrangements won't come into force until 1 October 2023.

4.3 How to achieve whole system thinking and design when networks are disparate

Under the current regulatory frameworks there is a tension between local and national effects. Wholesale pricing is set nationally, but network charging has a strongly local element: Ofgem sets incentives to minimise transmission costs, encouraging generation to be located close to demand. However, the optimal location for renewable generation is typically far from demand (e.g., offshore), meaning optimal renewable generation faces high transmission costs while less efficient generation is incentivised.

The system also lacks effective mechanisms for optimising actions in one network which may yield benefits in another network/voltage level, for example actions on the distribution networks which avoid costs on the transmission system. Where network company returns are regulated, there is a dis-incentive to such actions.

There is a growing debate within the industry, and from think tanks such as Policy Exchange and Energy Systems Catapult about whether a local or nodal pricing[21] approach should be adopted to more fully reflect the costs of electricity at the local level, and how the distorting effects of various compensation mechanisms should be addressed (Keay-Bright, 2021 and Keay-Bright & Day, 2021).

Nodal prices would be determined in real-time using an algorithm to calculate the incremental cost of serving one additional MW of load at each location subject to system constraints. Prices would include the full marginal costs of providing energy and reserves including costs of network losses and constraints.

> “Price signals in the spot markets are currently distorted by the presence of the capacity market (CM) and the contracts for difference scheme (CfDs), which essentially provide compensation outside of the wholesale market to some market participants. The CM and CfDs in effect muffle market signals. While the CM restores ‘missing money’ for existing resources, it creates ‘missing money’ for flexible resources, which is exacerbated if these resources are not able to access the CM or are significantly de-rated as is the case for batteries. The two schemes undermine the case for investment and innovation in business models involving DER.” (Keay-Bright & Day, 2021)

When capacity is added to the market through mechanisms such as the CfDs and Capacity Market, wholesale prices decline, exacerbating the so-called “missing-money problem”, and there is reduced need for investment in other capacity, including capacity not eligible for these schemes. Price suppression occurs when compensation is provided through mechanisms outside the main wholesale market, even if those mechanisms are procured through a competitive process (Brown & Reichenberg, 2020). The interactions of the different market mechanisms, including the Balancing Mechanism,[22] their design, and the behaviours of market participants to optimise revenues across these markets, all contribute to inefficient price signals.

Wholesale pricing is based on marginal pricing during half-hourly settlement periods, but as they exclude the costs of balancing and transmission, and because they lack granularity, their effectiveness as price signals for investment is muted. They are also increasingly disconnected from the underlying physics of the system. There are growing calls, particularly from consultants and think tanks for the market to become more granular both in time – with shorter settlement periods, and in space – with local or nodal pricing. There is a strong argument to shorten settlement periods, and for wholesale prices to include the costs of balancing actions to a greater extent. But the arguments for locational pricing are weaker, partly for reasons of social fairness – consumers in parts of the country which are far from sources of generation would face higher prices, and partly to do with reduced liquidity – electricity market liquidity in GB is not particularly high, and the liquid trading horizon is relatively short – breaking the market into smaller regional price zones would exacerbate these liquidity problems.

21 Under location-based pricing, prices would vary based on either nodes or points on the network (i.e., nodal pricing); or areas or zones with defined boundaries that reflect congestion (i.e., zonal pricing).

22 The primary means through which National Grid ESO procures the actions required to balance the system in real time.

Keay-Bright & Day (2021) propose a move to an energy-only market with a carbon dioxide cap under which suppliers would be required to deliver electricity with a declining carbon content over time, with the market determining the optimal combination of technologies to deliver that. They argue that existence of the Capacity Market dampens the effect of scarcity pricing in the short-term wholesale markets, which are then unable to fully reward flexibility and DSR. A related reform was proposed by Dieter Helm (Helm, 2017) in his cost of energy review, in which he suggested that electricity should be traded on the basis of equivalent firm power auctions where those generators that create intermittency on the system are required to bear the costs of mitigating it, by providing firm power rather than the current weather-dependent output.

Although the approaches differ, there is a recognition that the current market structures are failing to deliver the investments necessary to support the net zero transition, aside from large-scale renewable generation, and that without these investments, the value of additional renewable capacity will be diminished by increasing periods of curtailment (**Finding 6**).

4.4 How networks are accessed and paid for

Much of Ofgem's work on network reform has focused on fairness and affordability for today's consumers which has seen a net transfer of costs from consumers to (mainly renewable) generators. This is a zero-sum game as costs are later transferred back in the amounts that generators charge the buyers of their electricity, with these costs ultimately passed through to suppliers and end consumers. Ofgem's approach is focused on domestic consumers, yet energy intensive industries face significantly higher prices than competitors elsewhere in Europe, resulting in a major competitive dis-advantage.

Ofgem makes a central assumption that minimising investment in networks is most cost efficient for consumers, but this may not be a valid assumption since over the long term those investments might result in better consumer outcomes. Connection and reinforcement (expansion) costs are one of, if not the most significant barrier to deployment of renewable generation in the current regime.

A focus on short-term cost optimisation reduces incentives for transmission investment, meaning the output of renewable generation is often constrained, leaving consumers paying twice: once to subsidise construction, and then to curtail output. This focus on short-term cost optimisation arises from Ofgem's interpretation of its mandate, although, as several respondents to the House of Lords Ofgem and Net Zero inquiry suggested, Ofgem lacks accountability for its choices. Interestingly, one market participant interviewed for this report highlighted a corresponding issue of short-termism in the investor community, where company performance is measured against quarterly results, as an additional barrier to investments that may take longer to deliver benefits.

Network costs represent a significant proportion of end user bills, and the level of cost is growing due to the need to build new connections to generation located in different (non-traditional) locations, and to accommodate higher demand from individual premises with the growth in EVs and heat pumps. Costs associated with balancing the system are also growing. Ofgem has been working since December 2018 on changes to both forward-looking network charging and residual charging (the component of network costs which is not forward-looking).

Unfortunately, this effort has stalled, party due to other resource demands within Ofgem, and partly because the reforms have been undertaken in an unintuitive order, addressing residual costs before addressing forward-looking costs (residual costs are those that are left over once forward-looking costs have been recovered). There has been significant push-back from generators in particular, and the degree of overlap with other workstreams, has proved to be more complex than initially anticipated. Due to the significance of these costs, this contributes to investor uncertainty and is leading to projects being delayed.

4.5 How these changes fit within the price control framework

Network companies are local monopolies with multi-year price controls, based on a model which assumes a stable asset base, where the RPI-X concept centres on driving efficiency from a consistent operating model. However, networks will need to change significantly to enable the transition to net zero. There will inevitably be a need for more capacity as a result of electrification, but network operators will also need to adapt to capture the benefits of flexibility and demand-side response.

Ofgem encourages network operators to use flexibility (primarily load shifting) as a means of avoiding or deferring network reinforcement. But the regulatory model to date has deterred new investment on the basis that demand was stable or even falling due to efficiency measures. Now there is a need to marry a significant expansion in demand and therefore networks with a regulated asset model that assumes a stable asset base. While the increases in demand as a result of electrification have long been anticipated, the regulatory approach has heavily favoured incremental investments on a "just-in-time" basis: whether as a result of conservatism on the side of DNOs or Ofgem or both is unclear, but what is clear is that network operators need to be incentivised to fundamentally transform their businesses in support of net zero targets, and the regulatory approach will also need to change to enable this.

The new price control, RIIO-2, may struggle to deliver this outcome, since it contains fewer incentives and requires closer adherence to pre-agreed business models than the previous RIIO-1 model. RIIO-2 is essentially a reaction to the higher-than-expected profits earned by network companies in RIIO-1 which was unpopular with the general public, even though consumers may have benefitted. Since the early years of privatisation in which profitability was seen as highly desirable, the public mood has shifted, in part led by political populism. It is now increasingly unacceptable for energy companies to earn profits as a narrative of profiteering has become embedded in the public consciousness – a recent survey found that 34% of the public attributes the current gas price crisis to energy company profiteering (ECIU, 2022).

There are questions around how a rigid, multi-year[23] price control can support the necessary adaptability to support the energy transition. Although RIIO-2 contains a large number of re-openers there is a risk Ofgem's processes will be too slow or evidential hurdles too high for them to be used effectively. Conversely, frequent use of re-openers would effectively divide the price control into shorter periods. There is a developing trade-off: short price control periods limit long-term investment incentives, but longer periods may reduce network operators' flexibility to respond to rapidly changing market conditions. A further problem exists around the resourcing to support this type of ongoing review of the price control through its life – ideally, having finalised RIIO-2, Ofgem staff should turn their attention to designing the next price control, engaging with the market on the transformational frameworks required to support net zero. This will be difficult if they are pre-occupied with RIIO-2 re-openers.

Reconciling tightly controlled business models with the type of radical changes to business models that are needed, particularly within the traditionally passive distribution networks, will be highly challenging, and several of the energy professionals interviewed for this study expressed concerns that without a significant change in approach, it will be difficult to fully leverage the potential for flexibility and demand-side response. One participant described RIIO-2 as a "regulatory rabbit hole" with too many detailed rules. Strong signals need to be delivered to the market, and to investors, that future network business models will no longer centre around a stable legacy asset base. Significant innovation is required, and the risk profiles and therefore costs of capital for these businesses will need to change (**Finding 6**).

23 RIIO-2 will last for 5 years, down from 8 years for RIIO-1.

4.6 How security of supply is delivered

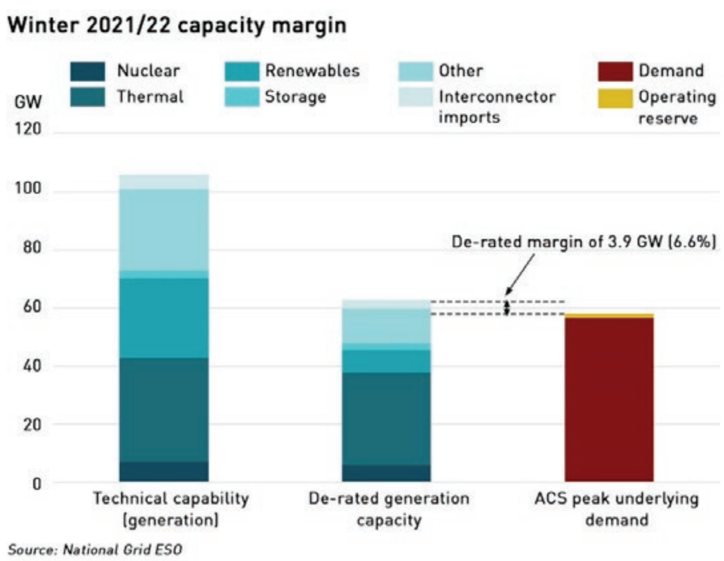
With the growth in intermittent electricity capacity, and the retirement of conventional thermal and nuclear generation, there are new challenges to ensuring security of supply. Winter capacity margins in particular have been falling, and winter power prices are higher and more volatile than has previously been the case. Falling capacity margins reduce the room for error – if National Grid ESO's assumptions on nuclear availability and interconnector imports prove to be too optimistic (Porter, 2021), the remaining capacity margins could quickly be eroded.

Periods of low wind output are a cause for concern, particularly because these weather patterns in winter are accompanied with low temperatures, boosting heating demand,[24] and these systems can extend across Northern Europe reducing the ability of imports to fill the gap.

Despite this, the Government expects that imports as well as new nuclear capacity will support security of supply in the future, although the commitment on new nuclear is likely to be inadequate over the medium term.[25] Technologies such as carbon capture and storage, and hydrogen are assumed to support security of supply in the long term, but so far it is unclear whether these will prove to be technologically or economically viable.

Security of supply is not only threatened by lack of capacity. It is also threatened by system instability, where the balance of supply and demand in real time falls outside operational tolerances leading to frequency deviations. System inertia is falling (National Grid ESO, 2021(b)) – by 40% in the past decade – and this, combined with increased variation in supply and demand, is making system frequency increasingly volatile and unpredictable. In addition, new capacity is increasingly large (interconnectors at 1.4 GW and Hinkley Point C will be 1.8 GW) – the loss of such large sources of supply combined with lower inertia makes the Rate of Change of Frequency high and requires a step change in how frequency is managed through response and reserve services.

Figure 22: Winter capacity margin, 2021/22



Source: National Grid ESO

24 While the majority of space and water heating in both the domestic and the industrial and commercial ("I&C") sectors is dominated by gas, around 15% of domestic and 8% of I&C space and water heating is electric, meaning that cold weather does boost electricity demand, albeit to a much lesser degree than gas.

25 The Government has committed to bring one new large-scale nuclear plant to Final Investment Decision before the end of the current Parliament (about another 3 years) – since the likely plant is EDF's Sizewell C European Pressurised Water Reactor which has a build time of approximately 10 years, new large nuclear capacity in addition to Hinkley Point C which is currently under construction will not be delivered before the 2035 target for the electricity system to reach net zero. (This relates to my earlier question – is it realistic to expect an FID on EDF's project in the next three years?)

Grid stability has traditionally been supplied as an inherent by-product of synchronous generation, but the increase in inverter-based technologies continues to drive a decline in the inherent stability of the system. Alternative sources of stability will be required to support net zero ambitions.

> "Operating the system with low inertia will continue to represent a key operational challenge into the future and we will need to ensure we improve our understanding of the challenges this will bring," – National Grid ESO

Voltage levels are managed through the injection and absorption of reactive power. Maintaining voltage levels on the transmission system has also become increasingly difficult as decreasing reactive power demand on distribution networks together with reducing power flows across the transmission network are driving an increasing need to absorb reactive power on the transmission network. The closure of coal and gas fired power stations is reducing the available reactive power capacity – 3,600MVAr of reactive capacity will be lost by 2025, and a further 1,000MVAr by 2030. National Grid ESO is exploring how to access reactive power from assets connected at the distribution level as well as understanding what impact the expansion of assets such as EVs and heat pumps will have on reactive power in future.

Network constraints are primarily managed through the re-dispatch of generation, but by 2030 some areas of the network are expected to have peak power flows 400% greater than current boundary capability, which exceeds the level which can be managed through re-dispatching generation alone. The Recast Energy Regulation requires National Grid ESO to limit the re-dispatch of renewable and high-efficiency cogeneration to 5%, but this threshold is likely to be exceeded before 2025. Between 2025 and 2030, generation from renewables is expected to exceed 50% of total demand, at which point the 5% threshold will no longer apply, however, the cost of re-dispatch is expected to rise significantly ahead of major network reinforcement. The growth in flexible resources should enable greater use of commercial solutions to manage transmission constraints as an alternative to large network reinforcements.

As unabated gas generation is phased out in the 2030s in the net zero compliant Future Energy Scenarios (National Grid ESO, 2021(a)), it will become even more challenging to maintain system security. Achieving this is likely to rely on the accelerated uptake of zero carbon technologies and carbon capture and storage (**Finding 5**). The profile of electricity supply will also change, with demand side response ensuring security of supply more efficiently.

4.7 How to manage the trade-offs between costs to consumers and environmental targets

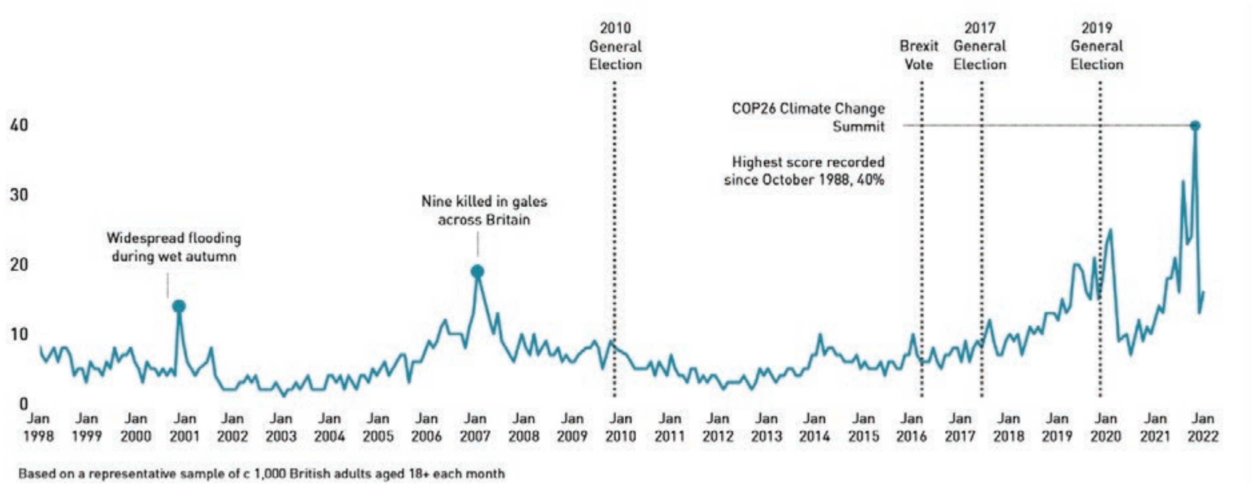
While Britons have reported an increasing degree of concern over environmental issues (Ipsos MORI, 2022 (a)), it is not clear that they are willing to make the necessary sacrifices to meet net zero targets. Britain Thinks found that people are uninspired by the Government's track record on climate, feeling there is an absence of a clear, unified narrative (2021). Few people have a clear picture of how net zero will be reached in practice, and there was strong concern among the survey participants that the UK government will be unable to move past party interests since they feel that climate change has been overly politicized and is generally used as a vote winner rather than a true government priority. There is a perception that efforts so far to tackle climate change have been unmonitored, and there is a lack of confidence in the Government's ability to achieve large-scale change in the required timeframe (**Finding 7**).

Figure 23: Attitudes to net zero – what people report climate change means to them

Source: Ipsos MORI, January 2022

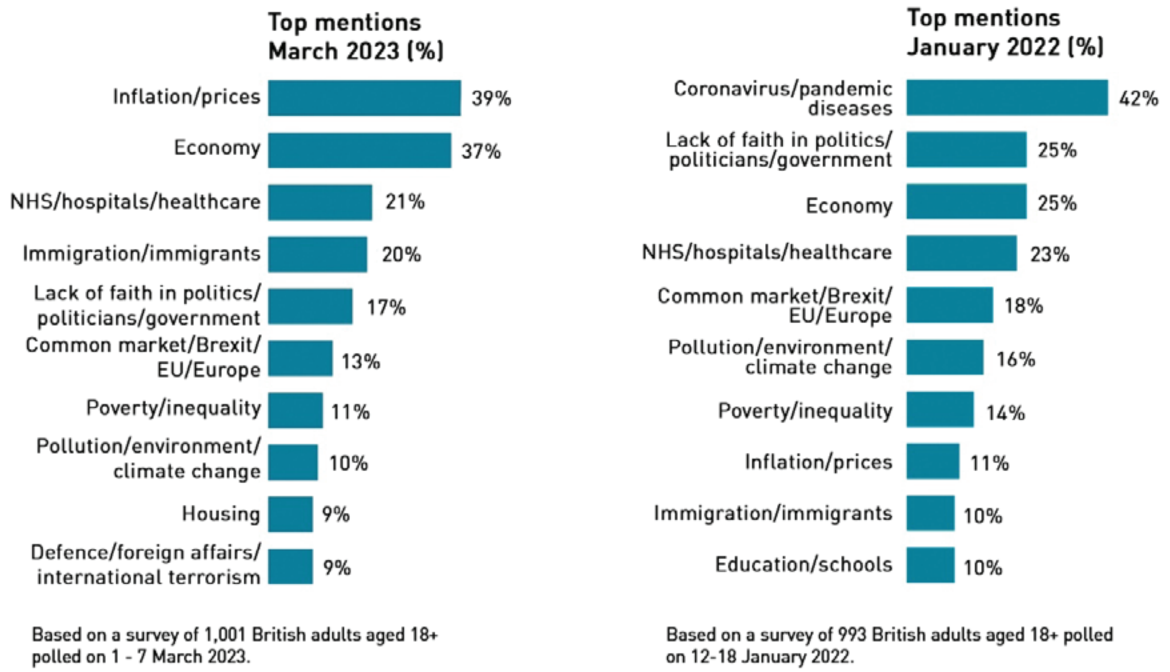
There has been a significant drop in the number of people considering climate change to be a key issue in the past few months (Ipsos MORI, 2022). Although the survey did not ask why, there are two likely reasons. The first is that a decline after COP-26 in October 2021, which was hosted in the UK and therefore attracted a great deal of media coverage, and the second is that since then, concerns over the cost of living, in part driven by rising energy costs have become more important to the public. Public concern over climate change continued to fall through 2022 and into 2023 (Ipsos MORI, 2023).

Figure 24: Percentage of respondents considering pollution/environment/ climate change to be one of the most important issues facing the country



Source: Ipsos MORI, January 2022

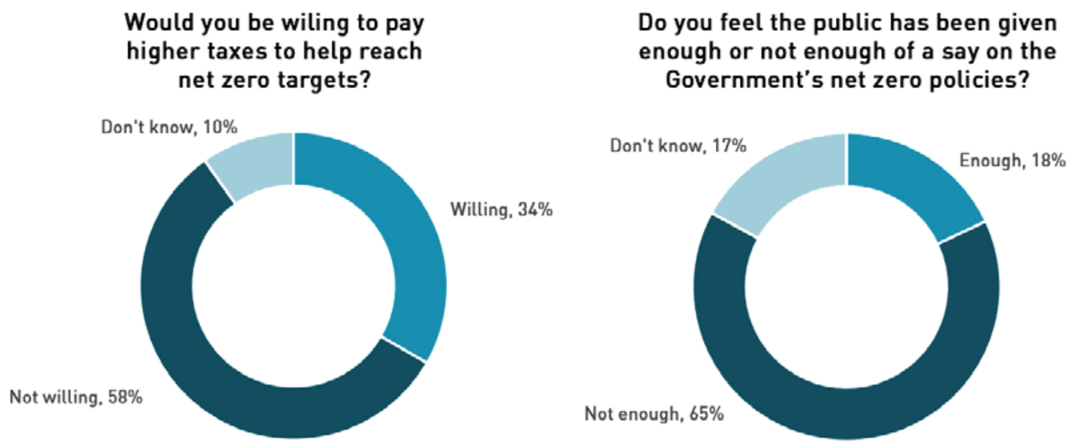
Figure 25: Survey of the main issues of concern for British citizens



Source: Ipsos MORI, January 2022 and March 2023

In a recent survey for Net Zero Watch (Net Zero Watch, 2021) conducted by Savanta ComRes, 70% of Britons said they were concerned about the financial impact of increased energy costs, while 58% said they would not be willing to pay higher taxes on their energy bills to help reach net zero targets. Two thirds of UK adults also said the public has not been given enough of a say on net zero policies, and 60% believe they won't benefit from government's environmental subsidies such as the grants for heat pumps and EVs. Some commentators are referring to net zero policies as a possible "Poll Tax" moment for the Government, referencing the most unpopular policy of the 20th century, which brought down Margaret Thatcher (**Finding 3**, **Finding 7**).

Figure 26: Public attitudes to net zero



Source: Savanta ComRes (Net Zero Watch, 2021)

These findings echo the results of research by Opinium for Bright Blue, a Conservative think tank (Sarygulov, 2020), which found that while people think the public, companies and government have a responsibility to help deliver net zero, they generally know little about low-carbon heating systems and are concerned about the costs. Younger people and those with higher levels of education are more likely to support the behaviour changes needed to achieve net zero, and people are more likely to support switching to green energy if someone else pays for it through subsidies rather than if they have to pay for it themselves through higher prices. The survey also found that 58% of the public believe it is unlikely that the net zero target will be achieved. This is consistent with the work of Britain Thinks which found that 64% of people were net pessimistic about the chances of meeting the net zero target, and that more engaged citizens tended to be more pessimistic than their less engaged counterparts (**Finding 5**).

Britain Thinks also found that participants feel dis-empowered by the current system of government and are sceptical about the power their vote has in creating positive change for the environment. But at the same time there was support for the Government taking action to force people to make the changes needed to support net zero:

> "A majority of the UK general public, and an even greater proportion of Net Zero diarists[26] (over 2 in 3), are concerned about individuals' willingness to make changes to their own behaviour without being forced to do so, but when spontaneously considering mechanisms for this, many (e.g., taxes, bans and penalties) were highly unpopular. Diarists feel this calls for greater leadership from government to ensure deadlines are not missed, however some caution is required so as to not alienate citizens."

Interestingly, one of the market participants interviewed for this report suggested that Britain's highly centralised system could be an asset in the transition to net zero allowing changes to be made at the national rather than regional level. This is supported by a recent Institute of Directors survey of over 600 business leaders (IoD, 2021), which found that 51% felt it was the role of government to advise businesses on how to reduce their carbon impacts, and 43% felt that it was the role of government to decide on the best way for firms to measure their carbon impact (**Finding 2**). 24% of businesses believe the cost of net zero should be met through general taxation, while 46% disagreed.

47% of businesses believe the price of carbon should be raised to incentivise greener energy sources, while 27% disagreed with this approach. This finding was interesting because it conflicts with the views of many commentators that recovery of green levies through energy bills is regressive for domestic consumers, and it also harms heavy industry which requires increasing levels of support and derogations from the effects of these additional charges. There have also been suggestions that if the costs are recovered through taxation instead then it will be easier to obscure them as they will be disguised in among the mass of other government expenditure, however, tax increases are also unpopular and Britain has traditionally followed a lower tax, lower state model than many other European countries.

The IoD survey took place in October, at the start of the recent rapid increase in wholesale price rises. Since then, rising energy prices[27] together with growing inflation and imminent tax increases to fund the NHS and social care are fuelling concerns over affordability, with only 13% of Britons being prepared to prioritise environmental choices if they mean higher costs (Ipsos MORI, January 2022 (b)).

26 The survey was conducted by asking participants to complete diaries of their thoughts on the topics in question.
27 Ofgem is due to announce the new retail price cap on 6 February which is expected to be significantly higher than the current level, which is contributing to concerns over affordability.

Emerging geopolitical risks with interconnectors

Several European countries, including GB, consider imported electricity to be a core part of the generation mix, and an alternative to domestic investments in new generation capacity. To the extent that this involves importing electricity that may have been subsidised by taxpayers or consumers in other countries, this may become a course of political tension, particularly if energy prices are rising in those countries.

In 2021, Norway commissioned two 1.4 GW interconnectors, one with Britain and another with Germany. As Norway's exports have increased, so have cross-border flows with Sweden, causing disruptions that have led the Swedish grid operator to reduce cross-border capacity by 75%. Prices in Denmark and Finland have risen, partly as a result of this move.

In Norway itself, electricity prices rose by a factor of ten in the year after these interconnectors opened. In winter 2021-22 the government increased its subsidies for domestic consumers to up to 80% of energy bills, and in winter 2022-23 these subsidies were increased to up to 90%. Assumptions that Norway could import cheap wind energy to save its hydro reserves have so far not played out, with Norwegian reservoir levels falling to historic lows during the summer of 2022. In January 2023 the Norwegian Government announced that it intends to bring forward legislation that would allow for electricity exports to be restricted in times of water shortages

A European energy market that has harmonised pricing but where policy decisions such as investments in generation and transmission capacity are still taken at the country level may have limits to its operation that could be tested in the near future.

On 3 February 2022, Ofgem announced a 54% increase in the capped standard variable tariffs ((“SVT”) officially known as the “default tariffs”) charged by energy suppliers (Porter, 2022). SVTs are the tariffs to which consumers are moved if they have a fixed price tariff which expires, and they do not choose a new fixed price deal. Since the recent increases in wholesale market costs, and because the price cap is only updated every six months, the capped SVTs have been the cheapest tariffs available in the market and have forced suppliers to sell below cost. As a result, a large number of suppliers went out of business in the second half of 2021. This significant increase in the cap level is primarily to adjust for higher wholesale prices (80% of the increase) as well as to account for the higher network costs which reflect the recover of the Supplier of Last Resort process used when a supplier fails.

On the same day, the Chancellor of Exchequer announced a range of measures to mitigate this increase to consumers, covering around half of the increase. These measures include a £200 discount to be offered to all consumers and structured as a loan to suppliers which will be repaid over 5 years through a £40 per year charge to consumers, and a £150 council tax rebate which will benefit around 80% of households. Other measures to promote energy efficiency for low-income households were also announced.

These measures were widely criticised, by politicians both within the Government and Opposition parties, the press, consumer groups and industry. They assume the rise in wholesale prices is temporary, which is not supported by forward curves or the views of analysts. The discount is to be repaid, so simply moves the cost increases in time, rather than removing them, and even with these measures, the increase in energy bills will be unaffordable for many.

Subsequently, it became clear that further support would be required, and that if widespread bankruptcies were to be avoided, support would also need to be put in place for businesses.

In September 2022, the Government announced two new support schemes: the Energy Price Guarantee[28] for households and the Energy Bill Relief Scheme for non-domestic consumers including public sector organisations, voluntary sector organisations such as charities, as well as businesses.

28 https://www.gov.uk/government/news/government-announces-energy-price-guarantee-for-families-and-businesses-while-urgently-taking-action-to-reform-broken-energy-market

The Energy Price Guarantee (EPG) supersedes the retail price cap, lowering the price paid by consumers to an average of £2,500 for a typical household on a dual fuel tariff paying by direct debit. This was in addition to the previously announced £400 rebate, giving an effective annualised cost of £2,100 per household for the duration of winter 2022-23 (initially the EPG was to cap prices at £2,500 for two years, but after the replacement of Liz Truss as Prime Minister by Rishi Sunak, the scheme was cut back due to its high cost).

Similar levels of support are available to households using alternative fuels such as heating oil and liquified petroleum gas, and the scheme also extended to households in Northern Ireland. In addition, the green levies applied to bills were suspended for the winter. These measures have been funded through taxation and Government borrowing, including a new windfall tax on oil and gas producers, and electricity generators other than gas and coal plant.

The price cap set by Ofgem was £3,549 for Q4 2022 and £4,279 for Q1 2023 so the EPG has reduced the price paid by households by a significant amount. Despite this, fuel poverty has risen sharply in winter 2022-23 and associated fatalities are expected to increase from the 8,500 deaths reported in the previous year.

Given the high cost of the EPG which is universal (ie not means tested), the level of support will drop from April 2023, with the Government capping prices at £3,500 for the following 12 months after which it is expected that consumers will be exposed to the full price cap although the Government is considering replacing the price cap with a social tariff targeted at the fuel poor.

When the Energy Bill Relief Scheme (EBRS) was first announced on 21 September 2022,[29] the expected maximum discount values were £405 /MWh for electricity and £115 /MWh for gas, however when the levels were confirmed in early October they were finalised at the lower amounts of £345 /MWh for electricity and £91 / MWh for gas.

The scheme applies to fixed contracts agreed on or after 1 April 2022, as well as to deemed contracts and contracts with variable and flexible tariffs and will cover energy usage from 1 October 2022 to 31 March 2023. The plan also includes the removal of green levies paid by non-domestic customers, which will be funded directly by the Government for the duration of the scheme.

The level of price reduction for each business varies depending on their contract type and circumstances:

- Non-domestic consumers with existing fixed price contracts agreed after 1 April 2022 receive the discount provided the wholesale component of their tariff is higher than the Government Supported Price. The Government published the wholesale prices used for calculating this for each day from 1 April 2022. Consumers entering new fixed price contracts after 1 October receive support on the same basis;
- Consumers on default, deemed or variable tariffs receive a per-unit discount on energy costs, up to a maximum of the difference between the Supported Price and the average expected wholesale price over the period of the Scheme. The amount of this Maximum Discount is £345 /MWh for electricity and £91 / MWh for gas.

The EBRS will be replaced from 1 April 2023 by a new scheme[30] for a further 12 months which will have a cost cap set at £5.5 billion based on estimated volumes, compared with the £18 billion cost of providing support through winter 2022-23. This new scheme will be available to entities on a non-domestic contract including who are:

- on existing fixed price contracts that were agreed on or after 1 December 2021
- signing new fixed price contracts
- on deemed / out of contract or standard variable tariffs
- on flexible purchase or similar contracts
- on variable 'Day Ahead Index' (DAI) tariffs (Northern Ireland scheme only)

29 https://www.gov.uk/government/news/government-outlines-plans-to-help-cut-energy-bills-for-businesses
30 https://www.gov.uk/guidance/energy-bills-discount-scheme

As with the current scheme, the Government will provide a discount on gas and electricity unit prices, subject to a maximum discount. A relative discount will be applied if wholesale prices are above a certain price threshold. For most non-domestic energy users these maximum discounts have been set at:

- electricity: £19.61 /MWh with a price threshold of £302 /MWh
- gas: £6.97 /MWh with a price threshold of £107 /MWh

The discount is calculated as the difference between the wholesale price component of the energy contract the business has with its supplier, and the price threshold. It is phased in when the wholesale price exceeds the floor price, until the total discount reaches the maximum discount for that fuel.

Energy and Trade Intensive Industries ("ETIIs") who are particularly vulnerable to higher energy costs and who may find it difficult to compete with businesses elsewhere facing lower energy costs will receive a higher level of support, also subject to a maximum discount which for these sectors will be:

- electricity: £89 /MWh with a price threshold of £185 /MWh
- gas: £40 /MWh with a price threshold of £99 /MWh

As with the original scheme, suppliers will automatically include reductions to the bills of all eligible non-domestic customers, however ETII customers will have to apply for the higher level of support. The Government will then compensate suppliers for the discount they are passing on to these customers.

5 Lessons for the future

Finding 1: Subsidies are an effective way of quickly decarbonising electricity but there are limits to what can be achieved without reforming the operation of networks

Deployment of renewable generation to date has been successful, supported by incentive schemes designed to reduce the cost of capital and deliver stable cashflows to attract investors, and the Government has plans to significantly increase renewable capacity, particularly in offshore wind. But there are concerns across the industry that without reform to the way in which networks are operated and paid for, and the mechanics of wholesale market price formation, these investments will fail to deliver the desired results, and the enabling investments in storage and demand-side flexibility will fail to emerge at the necessary scale.

Finding 2: There is a tension between market-driven solutions versus central planning

There is a tension between how much the markets can reasonably deliver (and whether the current market structures are appropriate) versus how much should be centrally planned. Businesses have reported a strong desire for Government to take the lead on the means and measurement of decarbonisation, and calls for re-nationalisation are made periodically, albeit without very much support. But in many ways, the current market structures emulate a centrally planned approach. The Government and Ofgem each intervene in the market in a variety of different ways in order to ensure certain desired outcomes, but with limited success. For example, the Capacity Market was originally intended to deliver large-scale gas generation and in particular CCGTs, and yet none has been delivered.[31] In fact, last year two 700 MW OCGTs secured capacity contracts, which is not optimal from an emissions perspective, and in earlier years, small diesel generators were so successful that their participation had to be limited through additional emissions regulation, since the Capacity Market rules are required to be technology neutral. There is certainly an argument that in a post-Brexit world, Britain should have secured the ability not to be bound by EU State Aid rules in the electricity market to enable the Government to offer direct subsidies, rather than having to adopt the convoluted approach currently taken in which almost every type of generation is entitled to compete for some form of state subsidy.

Finding 3: The costs of decarbonisation, which are borne by end consumers, are high and rising

Furthermore, the costs of decarbonisation, which are borne by end consumers through their electricity bills, are high and rising, at a time when wholesale energy prices and the wider costs of living are also rising. This is creating significant political pressure for action on high energy prices particularly for households but also for energy intensive industries, and there are growing debates among industry participants, consumer groups, politicians and the press about the public's appetite for both the costs of achieving net zero and the lifestyle changes that will be required.

Finding 4: Decarbonising electricity is significantly easier than decarbonising gas

The British experience shows that it is relatively straightforward to deliver a sizeable degree of decarbonisation in the electricity market, but that the challenges around low-carbon gas are significantly larger. But it also shows that there are limits to what a renewables-driven transition can achieve unless actions to mitigate intermittency are developed at the same pace. Many of the technologies that are assumed to be required for net zero such as carbon capture and storage, and hydrogen do not currently exist in any meaningful way, so to a large extent, the entire net zero strategy rests on the assumption that these technologies will emerge and be economically viable within the relevant timeframe.

31 The ESB Carrington CCGT which opened in 2016 took FID before the launch of the Capacity Market, so although it did secure a capacity contract, the investment decision had already been taken. SSE's Keadby CCGT is the first to be developed after securing a capacity contract and it is due to open in 2022.

Finding 5: The target of net zero by 2050 is short given the size of the challenge

The timeframe for net zero is short given the size of the project, so there are good arguments to support a centrally planned approach, which, while it may be less cost-efficient and may result in some policy mistakes, could well deliver faster results. On the other hand, governments have a poor track record of market planning, and in Britain, the previous nationalised model was characterised by significant over-capacity. Nevertheless, it is reasonable to question whether markets and competition can deliver the necessary solutions in the necessary timeframe, and unless markets are well designed, the problems of inefficient investments can still apply.

Although there are some significant differences between the British and Canadian markets – the highly centralised British political system and the un-bundled nature of energy markets being the two main ones, there are also similarities: distribution networks, while not owned by regional governments, operate within discrete geographic areas as local monopolies in both countries, so the questions about how monopoly price controls interact with the need to incentivise developments in network capacity, flexibility and demand-side response have some commonalities. Similarly, the need for the costs of decarbonisation to be affordable and fairly recovered is independent of market structure.

Finding 6: Whole-system thinking should be applied early, avoiding excess complexity

A key lesson from the British experience is around the need to avoid excess complexity, and to try to incorporate whole system thinking at an earlier stage. The multiplicity of market interventions in GB raises costs and barriers to entry and creates a legacy problem when looking to the next phase of the transition. Similarly, questions around wholesale price formation are ones which should be tackled head-on at an earlier stage so that prices signal the investments required to deliver the transition in a cost-effective and efficient manner.

Finding 7: Openness and transparency with consumers/voters is essential to maintaining public support for net zero

And finally, there should be open and honest debate with consumers/voters around the costs and risks of the transition. High prices are politically unpopular, contribute to fuel poverty and can lead to defeat at the ballot box, but the risks associated with failing to maintain secure energy supplies are more immediate and more significant since they can cost lives. Britons that lived through the 1970s still recall the hardships of regular blackouts and the three-day week with something approaching horror. It brought down governments at the time and created significant social unrest. A successful transition to net zero will only be achieved with the active agreement and co-operation of voters.

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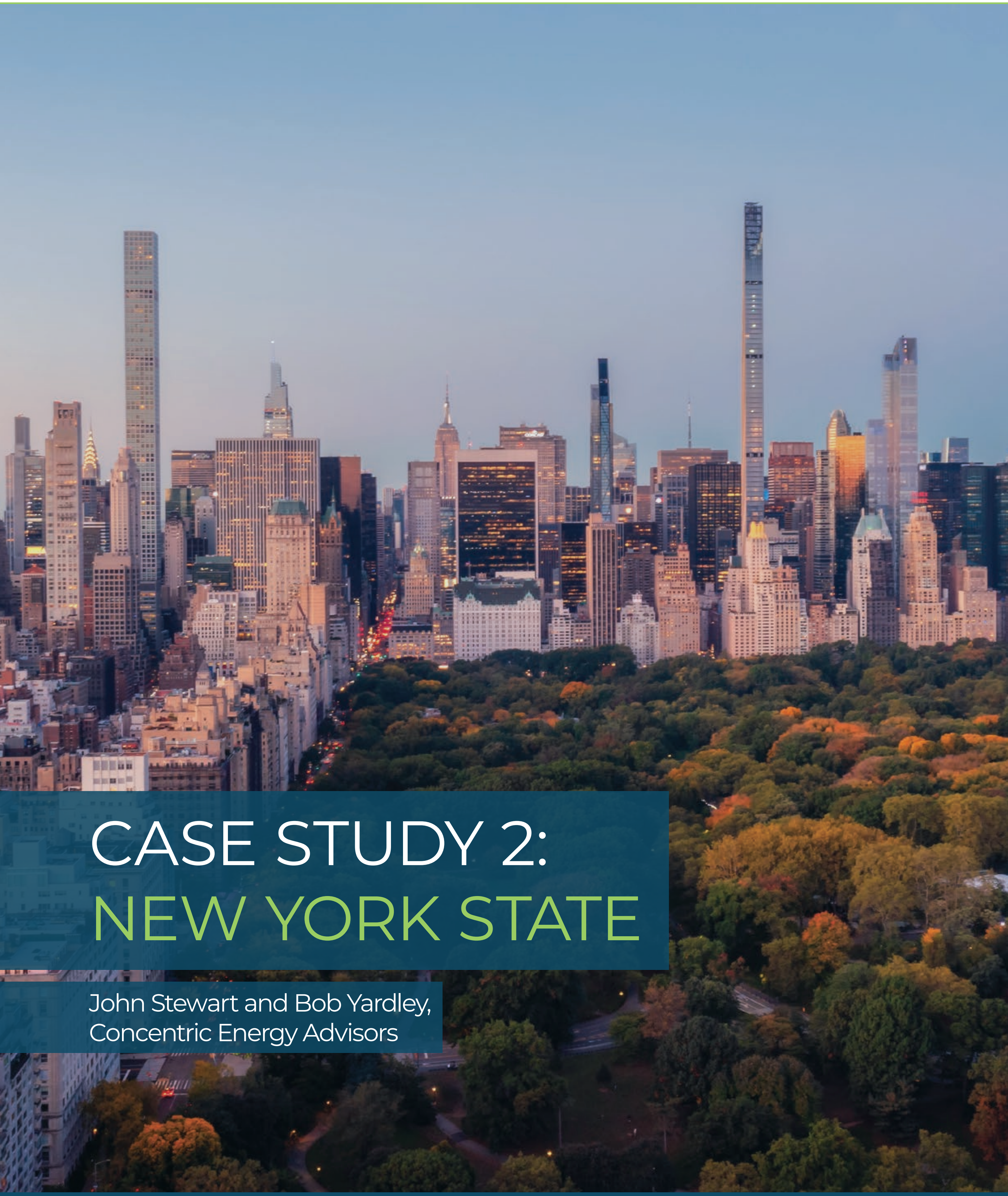

CASE STUDY 2: NEW YORK STATE

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1 Introduction

Many states are taking actions that respond to climate change, led by governors and legislators to demonstrate leadership on clean energy. These include states on the west coast (California, Oregon, and Washington), east coast (from the District of Columbia to Maine) as well as states in the middle of the country (Illinois and Colorado).[1]

1.1 Why a New York case study

The United States case study focuses on New York because it is far enough along the policy journey to begin addressing the most challenging implementation issues involving customers, business models, and infrastructure. Although many states take pains to make the point that "we are not New York", they are likely to encounter many of same challenges. New York is instructive for several reasons:

- New York's desired outcomes are representative of those being pursued in other US and global jurisdictions. Resiliency and environmental justice have been coupled with longstanding objectives such as reliability, affordability, and safety. Environmental justice, as the term has come to be applied in the New York and other states, refers to communities, and in particular, "disadvantaged communities", having the opportunity to participate in decisions that may affect their environment or health.
- New York is also representative of the diversity of interests that appear in many US jurisdictions reflected by distinct "downstate" (New York City) and "upstate" economies. New York City is one of the largest economies in the world with an aging infrastructure exposed by extreme weather conditions, such as rising sea levels during Hurricane Sandy (2012). Its population is diverse in every respect. New York City has been an active participant in energy policy debates for the last decade. Con Edison, the electric utility serving the City, has aligned its policies and practices with the City's energy needs including making investments supporting greater levels of reliability and resiliency. Upstate New York is more rural and interested in attracting industry to bolster a historically struggling economy. Siting new gas pipeline capacity has become nearly impossible downstate even as large shale gas reserves upstate are underdeveloped. There are pockets of environmental activism throughout the state with political influence.
- The legislature has been trending toward Democratic control, yet Republicans maintain considerable sway in the Senate. New York has elected governors from both parties. Governors have exercised enormous influence over energy policy, infrastructure development, and the structure of the utility sector.[2]
- New York is one of the few states that has established greenhouse gas (GHG) targets by statute as part of a trend that is appearing in other jurisdictions. However, the enabling investments and utility decarbonization programs to achieve the targets – as well as the rates to be paid by customers – are approved in periodic rate cases filed by electric and gas utilities. This places New York at the forefront of states that will need to address conflicting objectives including reconciling environmental mandates with potential, if not likely, upward pressure on energy bills. Two recent filings will test the resolve of the New York Public Service Commission (PSC) with orders expected later this year. First, Consolidated Edison of New York has reached a 3-year settlement agreement that incorporates large rate increases due in part to efforts to make progress toward the GHG targets (companion electric and gas rate cases – Case 22-E-0064 and Case 22-G-0065).[3] Second, National Fuel has filed the first natural gas Long-Term Plan reflecting a tempering of decarbonization to restrain rate and other cost impacts (Case 22-G-0610).[4]
- Finally, New York provides an excellent example of the struggle of policy makers and regulators with the tension between a command-and-control approach to achieving environmental targets vs. reliance on pricing and markets. This struggle predates the focus on environmental goals, dating back to the divestiture of generation assets by utilities in the late 1990s and the establishment of the New York Independent System Operator (NYISO).

1 This case study has been updated since the initial publication of the Net Zero Report in March 2022 to incorporate policy developments over the prior 12 months.
2 One extraordinary example was the merger of LILCO and Brooklyn Union in 1996 and the creation of the Long Island Power Authority.
3 Case 22-E-0064 et.al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service*, Joint Proposal (dated February 16, 2023).
4 Ratepayers advocates have expressed opposition to the Consolidated Edison agreement; environmental advocates have expressed opposition to National Fuel's proposed Long-Term Plan.

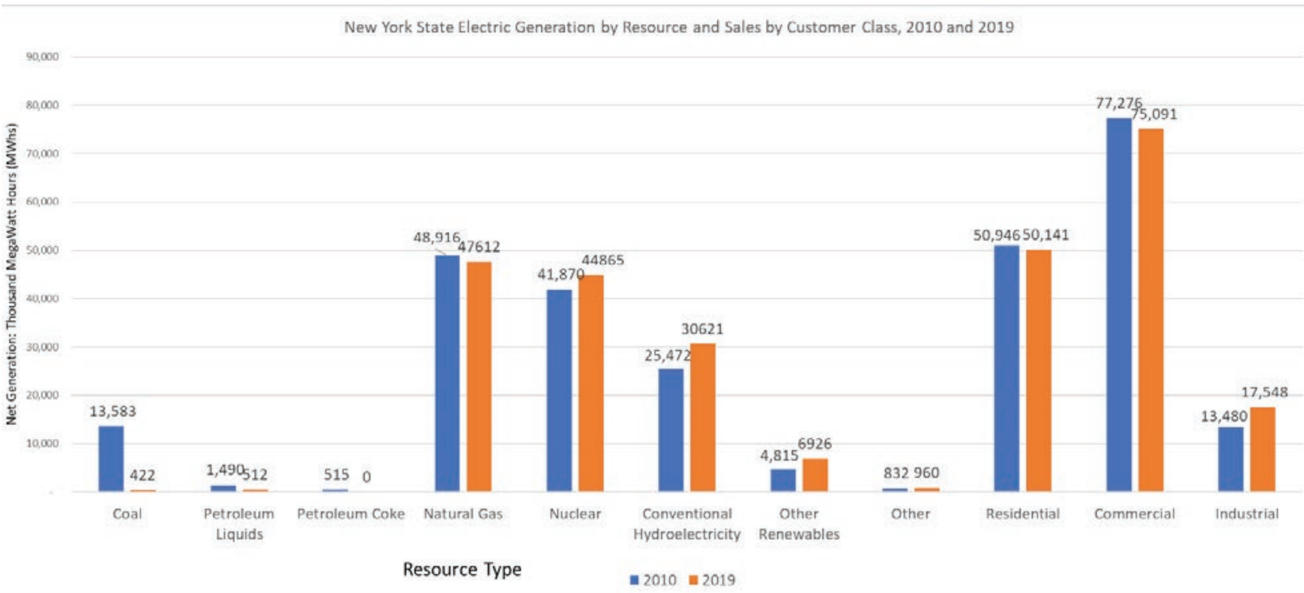
2 Present context

Although the restructuring of New York's energy sector began in the late 1990s, the enactment of the *Climate Leadership and Community Protection Act* (CLCPA) on July 18, 2019 with an effective date of January 1, 2020 marks a clear demarcation in New York's energy policy and serves as a useful marker for defining the "current context". The substantive implications of the CLCPA are described in this section; the historical context is provided in Section 3, and its genesis and current process implications related to implementation are addressed in Section 4. This section starts with a description of the changing characteristics of the energy landscape in the State between 2010 and 2020.

2.1 Characteristics of the energy landscape in New York

The following figures compare information reflecting New York's electric generation mix, electric customer class sales, and natural gas sales in 2010 and 2019.[5] Figure 2 shows that: (1) the State has eliminated its reliance on coal generation over this period; (2) continues to rely heavily on natural gas, nuclear, and hydroelectric generation; and (3) the State's reliance on renewable resources has increased by about 50 percent. This figure also shows that while residential and commercial sales have remained flat, industrial sales increased by about 30 percent – a statistic that may have been influenced by the lingering effects of the recession in 2010.

Figure 1: Sales by fuel type and customer class



5 NYSERDA reports CO_2 emissions from the electric utility sector of 37.2 MMtCO2e in 2010 and 22.1 MMtCO2e in 2019 (2020 data is not yet available).

Figure 2 shows that New York's reliance on coal in 2010 has been virtually eliminated due to natural gas generation and renewable energy. Renewable energy capacity (hydroelectric, solar, and wind) increased by 1,440 MW over this period, a 26 percent change.

Figure 2: Generation capacity by fuel type

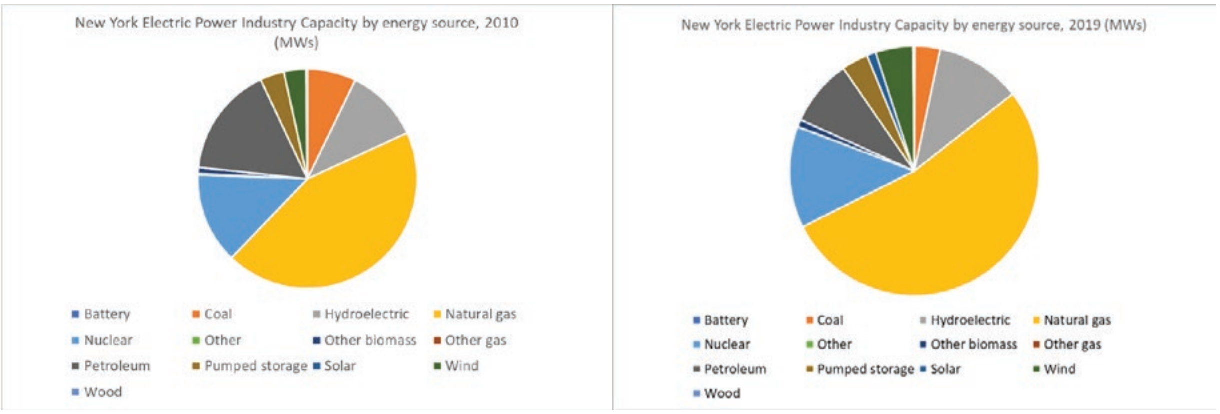
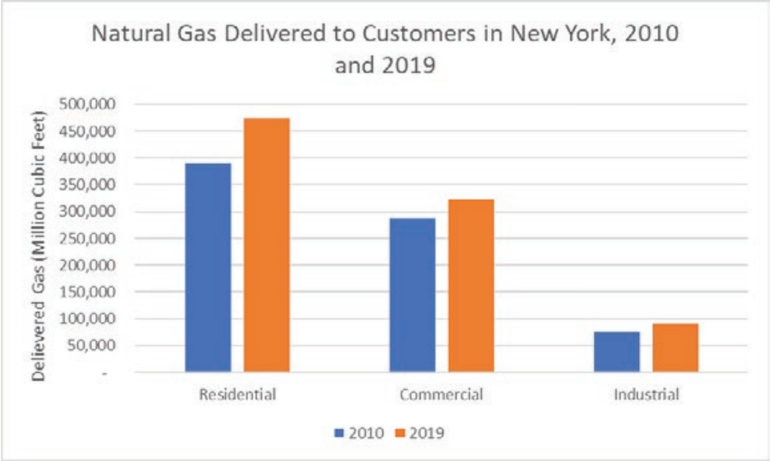


Figure 3 shows that natural gas use increased in all three segments over the study period.[6]

Figure 3: Gas delivered by class



2.2 Transition from clean energy "goals" to "mandates"

The CLCPA established mandates for New York to reduce economy-wide GHG emissions from a 1990 baseline by 40 percent by 2030 and 85% by 2050. It also marks a change in the process of establishing policy in New York as the legislature has not engaged in major energy legislation over the preceding few decades.[7] Converting goals to statutory mandates significantly sharpens the responsibility and approach of the New York Public Service Commission (PSC) and other state agencies when making decisions that potentially impact GHG emissions. The CLCPA also reflects the lobbying of legislators by environmental justice advocates as it includes the establishment of "disadvantaged communities" and specific requirements that benefits be targeted to these communities.

6 Figures for 2020 are not yet available.

7 Remarkably, the restructuring of electric generation and initiation of competitive retail choice were accomplished through Commission action in New York without legislation which is typically seen as in most states.

The CLCPA also has enormous implications for New York's electric and natural gas utilities to achieve the mandates in Table 1.

Table 1: CLCPA requirements

Renewable Supply	Jurisdictional load serving entities must rely on renewable generation to serve at least 70% of load by 2030
Wind and Solar Generation	Install 9,000 MW of offshore wind and 6,000 MW of distributed solar energy to serve New York by 2035
Zero Emissions Target	Zero emissions associated with meeting electrical demand by 2040 (defined by EPA as Scope 1 emissions)
Clean Heat	Calls for measures that reduce energy use in existing residential or commercial buildings, and the beneficial electrification of water and space heating in buildings
Transportation	Strategies that address electrification of personal use and fleet transport
Energy Efficiency	Reduce energy consumption by 185 trillion British thermal units (BTUs) from the 2025 forecast
Energy Storage	Install 3.000 GW of energy storage by 2030

Notably, the CLCPA includes incredibly broad language that would require all state agencies to consider the impact of "approvals and decisions" on the attainment of GHG emissions limits.

> In considering and issuing permits, licenses, and other administrative approvals and decisions, including but not limited to the execution of grants, loans, and contracts, all state agencies, offices, authorities, and divisions shall consider whether such decisions are inconsistent with or will interfere with the attainment of the statewide greenhouse gas emissions limits established in article 75 of the environmental conservation law. (CLCPA, Section 7(2))

The question as to whether this provision applied to rate cases was addressed by PSC in approving a 3-year rate case settlement involving two National Grid subsidiaries in what the Commission characterized as "the most contested issue is these proceedings". National Grid had filed its rate case before the CLCPA was enacted. Nonetheless, the Commission determined:

> Although we find some ambiguity regarding this language, particularly with the directive to identify "mitigation measures to be required where such project is located," we believe that our decision best aligns with the Legislature's intent that Section 7(2) of the CLCPA be broadly construed. (PSC KEDLI, KEDNY Order, p. 69)

The Commission's order further acknowledges that the "CLCPA is still a nascent law whose implementation remains a work-in-progress in the State," and that the Department of Environmental Conservation has yet to "provide guidance regarding how the emission limits will apply to individual sources of greenhouse gas emissions or even individual sectors of the economy." (PSC KEDLI, KEDNY Order, p. 72)

The Commission determined that the settlement was "fully consistent" with the CLCPA citing settlement provisions that require demand-side programs, "such as energy efficiency, demand response, geothermal, and electrification options, and thereby meet customers' energy needs in lieu of traditional infrastructure projects" as well as consideration of non-pipe alternatives and actions to detect and repair methane leaks. (PSC KEDLI, KEDNY Order, p. 74). Most notably, the companies had agreed to discontinue activities that would expand natural gas use. (p. 75)

In its January 2022 rate case, Con Edison filed over 200 pages of testimony addressing matters related to the CLCPA. (Case 22-E-0064). Many, but not all, of the recommendations in this testimony were adopted as part of the rate case settlement. The Joint Proposal crafted by these parties is now being considered by the Commission. The Joint Proposal incorporated levelized increases in electric and gas delivery rates spread out over a three-year period of 19.8 percent and 31.3 percent respectfully. The Joint Proposal is now before the Commission and its substantial rate increases will serve as a litmus test to judge the willingness of the Commission, elected officials, and the public to pay the costs associated with a clean energy future. Notably, the Public Utility Law Project, a staunch consumer advocate has publicly opposed the Joint proposal.

The CLCPA established a Climate Action Council (CAC) that was charged with developing a Scoping Plan that addresses the many implementation challenges to achieving emissions reductions in all sectors of the New York economy, including the energy sector. In theory, the statute launched a transparent, inclusive pathway exercise. However, the Council membership, appointed by the Governor, was comprised of 12 representatives of state agencies and authorities (two serving as co-chairs), and ten "appointees", dominated by environmental interests. The CAC is headed by the leaders of NYSERDA and the Department of Environmental Conservation (DEC) with advisors consisting of ten state agency heads, including the Chairman of the Commission. National Fuel Gas Corporation was the only utility among appointed participants and declined to sign on to the Final Scoping Plan, issued on December 19, 2022; no electric utility representative was appointed. It is possible that utilities will have more influence over the outcomes from PSC regulatory processes that will be initiated to address implementation details.

The legislature passed a second piece of legislation that recognizes the fact that it will not be possible to achieve the CLCPA's renewable energy targets without investing in transmission and distribution capacity. The *Accelerated Renewable Energy Growth and Community Benefit Act* of April 3, 2020, directed the Commission to work with the NYISO and States' electric utilities to identify bulk and local transmission upgrades and distribution network upgrades necessary to connect and deliver large-scale renewables from renewable energy projects (including off-shore wind) to in-state markets.

Finally, on July 5. 2022, Governor Hochul signed the *Utility Thermal Energy Network and Jobs Act*, authorizing utilities to own and operate thermal energy networks and directing the PSC to initiate proceedings to support and regulate the networks. The PSC subsequently initiated Case 22-M-0429 and has required utilities to submit proposed pilot projects.[8]

8 Case 22-M-0429, *Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act*, (issued September 15, 2022)

2.3 New York's current energy profile and market structure

The New York Independent System Operator

New York is one of two states with a single-state RTO/ISO (the New York State Independent System Operator (NYISO)), regulated by the Federal Energy Regulatory Commission (FERC).[9] While this creates an opportunity for better coordination of wholesale and retail/distribution markets within New York, the state has limited authority over the NYISO and relies on pressure exerted through the New York utility transmission owners to influence policy. At the end of the day, however, the NYISO tariff and wholesale markets are regulated by the FERC based on the longstanding principle that because wholesale transactions (and the transmission assets supporting them) represent interstate commerce they are subject to Federal jurisdiction.[10] The NYISO, as do other ISOs, focuses on system reliability and all transmission owners including the State's utilities ceded operational control of the transmission system to the NYISO as part of the industry restructuring in the 1990s. Climate-forward states, including New York, Massachusetts, and Connecticut, have concluded that achieving GHG emissions targets and integrating distributed energy resources (DER)[11] requires an integrated approach to infrastructure planning, operations, and markets between the FERC-regulated ISOs and state-regulated distribution companies. The NYISO and New York distribution utilities have been working on better coordination on integration (planning, operations, and market design) of distributed and large-scale renewables.[12]

There have been other successes as well. FERC Rule 1000 has been aggressively implemented by the NYISO through its Public Policy Transmission Planning Process (PPTPP) in close coordination with the Commission. The Rule has led to the development of major reinforcements to the current transmission grid to help bring more clean energy to New York City.[13,14]

Pursuit of state environmental objectives can result in potential conflicts within the NYISO market. For example, the PSC implemented a zero-emissions credit (ZEC) framework as part of the Clean Energy Standard intended to provide financial support to New York's operating nuclear plants that has invited a court challenge from non-nuclear generators.[15] While the ZEC credit was justified by the value of avoided emissions from nuclear generation, it was developed because wholesale energy and capacity prices in upstate New York would not cover nuclear running costs and its quantification reflected an amount deemed sufficient to keep the State's four upstate nuclear plants operational. There is no trading market for ZECs, it is a pure subsidy to keep nuclear plants afloat.

Finally, the September 2020 issuance of FERC Order No. 2222 addresses the treatment of behind the meter energy storage that purchases energy from the wholesale market and sells excess energy into the market. This has resulted in substantial body compliance efforts by the NYISO to implement tariffs that enable these transactions. Reflecting considerable collaboration with the NYISO, New York's electric utilities will file FERC wholesale distribution tariffs in early May.

9 California is the other state. The Electric Reliability Council of Texas (ERCOT) serves a similar function within the boundaries of Texas but is not subject to FERC regulation.

10 FERC authorities are established by statute, with many of its authorities dating back to Parts II and III of *Federal Power Act* of 1920 establishing exclusive jurisdiction over the transmission of electricity by public utilities in interstate commerce, rates and services of interstate gas pipeline and storage facilities, the sale of electricity at wholesale by public utilities (including sales for resale), and oversight of energy markets. FERC 101 provides an overview of the FERC in presentation format.

11 DER is generally defined as behind-meter-resources that impact the generation of electricity in the wholesale markets. DER includes behind-the-meter generation (principally solar), energy storage, energy efficiency, and demand response.

12 Order No. 2222, 172 FERC ¶ 61,247

13 This has led to transmission lines proposed by NextEra Energy Transmission New York, Inc., New York Transco, and LS Power. All three projects support the transmission of larger amounts of upstate clean energy to the New York City area. A 2019 report by the Brattle Group showed that the NYISO had added a larger percentage of transmission resources as the result of FERC 1000 than any of the other regional ISOs.

14 The Commission has instituted a transmission planning case under which the utilities must develop plans for traditional intra-state transmission assets as well as the assets that will be required to meet the CLCPA challenges. The NYISO has been a participant in that proceeding.

15 On Oct. 19, 2016, several electric generators, including Dynegy and NRG Energy, and others filed a lawsuit with the U.S. District Court for the Southern District of New York alleging that the subsidies intrude on the exclusive authority of the FERC over the sale of electric energy at wholesale in interstate commerce. These challenges were rejected in the Federal Courts.

Retail competition

New York introduced retail competition during the initial industry restructuring in the late 1990s for both electricity and natural gas. The overwhelming majority of small commercial and residential customers continue to purchase their electricity and natural gas from their distribution utility under a "provider-of-last-resort" (POLR) service. In both cases, the utility provides the commodity at a partially hedged price. All larger electric and gas customers purchase their commodity directly in the NYISO/gas markets or through an energy services company (ESCO).

2.4 Policymaking and regulation

With legislators historically taking a less active role than in other states, policy making has been dominated by the governor's office with distinct, but increasingly coordinated roles served by the PSC and the New York State Energy Research and Development Authority (NYSERDA).[16] Historically, and to a greater extent over the past decade, the governor has exercised an unusual degree of oversight of the PSC including providing input and feedback on draft orders, an extraordinary relationship with a quasi-judicial agency.[17] This has been largely enabled by the facts that the PSC chairman is appointed by and serves at the pleasure of the Governor and the senior advisors to the Commission serve at the chairman's pleasure and in some cases have no civil service protection.[18] The PSC is one of the largest in the country with a staff of over 500 and serves multiple roles including: policy maker, policy implementer, utility auditor, and rate setter.

As discussed further in Section 4, the enactment of the CLCPA and conduct of the CAC are indicative of current power dynamics that have been evolving over the past few years:

- The Governor remains the center of power, to a degree not experienced in most other states where legislatures tend to be more active and where the regulatory commission exercises a greater degree of independence from the executive branch.[19] The upcoming November 2022 election is not expected to change the current policy direction, including the final CAC report.
- Environmental justice advocates had considerable influence during the drafting of the CLCPA. (Aidun, et. al, 2021)
- NYSERDA's role as a policy maker and market participant has grown, particularly as it relates to securing large scale renewables and influencing the development of transmission necessary to move wind energy from offshore to market centers.
- Well-funded environmental non-governmental organizations (NGOs) including the Environmental Defense Fund (EDF), National Resources Defense Council (NRDC), and the Sierra Club are active in both the political and regulatory arenas, aggressively pursuing their agenda. They have become active and effective participants in utility planning proceedings (where key infrastructure decisions are influenced) and in utility rate cases where 3-year settlements are the norm, opening the door for NGOs and other special interests to extract concessions that advance their agenda but may not impact the overall revenue requirement. Absent these concessions, they may oppose the settlement.
- New York's electric utilities have had greater success influencing policy at the PSC than with the Administration (i.e., the Governor's Office and NYSERDA) or at the legislature. The utilities remain on the defensive in many areas including the roles that they can serve and their ability to be fairly compensated for the risks that they are asked to absorb.

16 NYSERDA is a public benefit state energy agency that offers information, analysis, programs, and technical expertise to help New York consumers increase energy efficiency, save money, use renewable energy, and reduce reliance on fossil fuels.

17 This was particularly evident during the term of Governor Andrew Cuomo (2011 - 2021). Governor Cuomo resigned and was replaced by his Lieutenant Governor, Kathleen Hochul on August 24, 2021, a Democrat from upstate New York. Governor Hochul has announced her intention to seek election to a four-year term in November 2022 and has strongly supported the State's clean energy efforts.

18 The Commission, as permitted by law, adopted a resolution in 2021 expanding the number of commissioners from five to seven. Commissioners are appointed by the Governor and confirmed by the Senate to six-year terms.

19 The Governor's office also exerts leverage over the New York Power Authority, a public owner of generation and transmission infrastructure and provider of energy services to public power and industry, that is in a position to contribute to achievement of the CLCPA targets.

3 Evolution of New York's energy policies

This section briefly reviews major policy developments in New York, dating back to efforts by the FERC to introduce competition into the natural gas industry.

Three dimensions are emphasized:

- The degree to which policy design relies on market forces, including competitive forces, pricing, and the options available to customers;
- Efforts to support the development of clean resources, including energy efficiency; and
- Evolution of policy priorities and their relative importance.

3.1 Restructuring of the natural gas industry

The restructuring of the natural gas industry in the late 1970s continuing into the 1980s introduced competition through a series of FERC policy orders by applying economic principles that addressed the question as to whether each segment of the industry was a natural monopoly or whether the services were subject to competition. Sequential policy decisions unbundled the commodity from the interstate transmission of natural gas, unbundled storage from transportation (allowing market-based pricing if certain standards were met) and established a competitive secondary pipeline capacity market. These policies enabled state regulators to allow larger customers to arrange their own supplies or acquire a delivered supply service from a marketer.

Regulators focused on economic efficiency that would lower total delivered cost of natural gas to consumers. The success of these policies caused state and federal policy makers and regulators to examine the electric industry by beginning to question whether generation could be unbundled from transmission and distribution services. In a similar vein, regulators increasingly looked to behind-the-meter solutions for introducing greater efficiency. Energy efficiency efforts for both gas and electricity came to the forefront in the early 2000s. New York currently uses less energy per capita than any other state.

3.2 Restructuring of the generation segment in New York and other states

Policy makers in New York and other high-cost states responded to the emergence of independent power producers developing efficient combined cycle plants and demanding the opportunity to compete against existing generation.[20] In 1996, the PSC, without the need for legislation, but supported by Governor Pataki, directed the state's electric utilities to divest generation along with the ability to recover any stranded costs.[21] In the same period, the FERC created regional RTOs/ISOs in New York and other regions that assumed responsibility for reliability and established markets for capacity, energy and ancillary services. Upon establishment of the market, customers were afforded the opportunity to purchase energy and capacity from competitive energy service companies.[22]

20 State regulators were frustrated with safety-driven cost overruns at new nuclear plants and being placed in the position of deciding whether particular plant investments or purchased power contracts would benefit customers, frequently requiring oversight of RFP design and outcomes. This, along with consideration of energy efficiency as a "resource", led to the emergence of Integrated Resource Planning in the early 1990s.

21 Case 94-E-0952 *et. al., In the Matter of Competitive Opportunities Regarding Electric Service* (Competitive Opportunities Proceeding), Opinion and Order Regarding Competitive Opportunities for Electric Service (issued May 20, 1996) (Competitive Opportunities Order), pp. 12, 28-29, 69-70.

22 Competitive Opportunities Proceeding, Competitive Opportunities Order, pp. 36-42.

This continued a regulatory policy trend toward reliance on market forces in energy sectors that were potentially competitive. However, designing wholesale electricity markets has proven to be much more complicated than anticipated and market designs continue to be modified in response to undesirable outcomes including sustained price spikes, evidence of market manipulation, or inability to attract clean generation capacity within constrained market areas such as New York City. Most observers agree that, on balance, economic benefits have been derived from the restructuring of generation with wholesale power markets, and increased attention to energy efficiency with utility integrated resource plans (IRPs). State regulators in New York and New England are currently promoting change to incorporate environmental attributes into ISO capacity and energy market rules.

3.3 Reality strikes: Hurricane Sandy

After experiencing significant utility problems associated with Hurricanes Irene (upstate in 2011) and Sandy (New York City/Long Island/upstate New York in 2012), Governor Cuomo's dissatisfaction with New York's electric utilities publicly manifested itself on a number of occasions. On one occasion he stated that "We're going to have to look at a ground-up redesign [of the utility system]."[23] This contributed to increased attention by the Governor's office to electric distribution utilities. These events also served as a reminder that "resilience" of energy infrastructure is an important policy objective and distinct from oversight of "reliability".

3.4 New York's efforts to restructure the electric distribution segment

The *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding" or "REV" for short) (Case 14-M-0101) was initiated on April 24, 2014 by a Commission order accompanied by a 66-page Staff Report and Proposal presenting the Commission's vision.[24] The initiating order revealed the vision for a future that would rely on distributed energy resources involving a "reconsideration of the utility business model, including the relationships among utilities and customers, bulk markets, and regulators" referring to "a new business model for energy service providers in which DER becomes a primary tool in the planning and operation of electricity systems, and in which customers are empowered to optimize their priorities with respect to reliability, cost, and sustainability."[25] The Commission identified six policy objectives that collectively signaled an interest in a restructuring that increased economic efficiency while resulting in a reduction of carbon emissions as the sixth objective added at the insistence of Staff.[26]

REV presented a theoretical "platform" business model (the Distributed System Platform) that had been advanced by academics and supported by third parties seeking access to utility customers and business models. This model was intended to increase the efficiency of a system that would include supply side resources as well as DER, while serving as a foundation for clean energy.[27] The Commission issued seminal "Track 1" (business model) and "Track 2" (regulatory changes and ratemaking issues) orders. These orders introduced an entirely new set of topics for Commission consideration related to the role of DER (defined generally, as behind the meter generation, energy storage, energy efficiency, and demand response) in the electric markets, the manner by which DER would be coordinated with existing resources, and the regulatory model(s) under which utilities would operate in this new world.

23 *See e.g.*, https://www.reuters.com/article/storm-sandy-utilities-cuomo-idCNL1E8M8AGE20121109
24 "Reforming the Energy Vision, NYS Department of Public Service Staff Report and Proposal", Case 14-M-0101, April 24, 2014.
25 Initiating REV Order, p. 4.
26 (1) Enhanced Customer knowledge and tools that will support effective management of their total energy bill, (2) Market animation and leverage of ratepayer contributions, (3) System wide efficiency, (4) Fuel and resource diversity, (5) System reliability and resiliency; and (6) Reduction of carbon emissions.
27 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (REV Proceeding), Order Instituting Proceeding (issued April 25, 2014) (REV Order), pp. 3-5.

REV morphed into a complex proceeding that addressed numerous policy and implementation matters. Utilities were precluded from owning DER except when considered to be an integral part of network facilities.[28] While this potentially restricts the growth in DER, the Commission wanted to encourage DER providers to operate in New York. The business model introduced competition for traditional utility network investments by introducing non-wires alternatives (NWAs) as a way of avoiding large grid investments, while also providing ratemaking incentives that compensate the utilities for foregone rate base.[29] These incentives are structured to allow the utility to retain a portion of the annual net benefits from contracting with an NWA.[30] New York's electric utilities are required to file periodic Distributed System Implementation Plans (DSIP) that present grid modernization and planning, operations and market enablement activities that will enable deployment and integration of DER.[31]

The Commission discontinued net metering as an option for new customers (grandfathering existing customers) and established the Value Stack as an approach for compensating injections from DER. Under a Value Stack compensation methodology, DER that injects electricity will be paid for its wholesale energy value, wholesale capacity value, locational value to the grid, and if it is clean energy, the value of avoided emissions.[32] As part of this same proceeding, the PSC authorized community distributed generation,[33] remote net-metering,[34] and Community Choice Aggregation.[35] These programs were designed to promote solar energy development.

REV also encouraged the development of emerging technologies including electric vehicles and energy storage. The Commission created an Electric Vehicle Make-Ready program in 2020 under which utilities will pay utility costs and some costs on the other side of the meter to prepare sites for installation of EV charging equipment.[36] Utilities were permitted to defer and amortize expenditures under the program.[37] The legislature also passed legislation at the end of 2021 directing the Commission to explore alternative rate designs and other approaches to improve the business model for commercial owners of EV chargers.[38] This recently culminated in a Commission order directing the electric utilities to develop programs that provide owners of commercial chargers varying levels of relief from demand charges (in the form of discounts) if their load factors are below 25 percent.[39]

There were initial utility concerns among electric utilities that greater amounts of behind the meter resources spurred by REV would reduce electric utility sales and create the potential for rate increases that would incent greater amounts of DER and further sales reductions (death spiral). These concerns have dissipated as the result of the massive electrification effort required by the CLCPA.[40]

28 *See e.g.,* Case 18-E-0130, *In the Matter of Energy Storage Deployment Program*, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018), pp. 41-45.
29 *See e. g.,* Case 14-E-0302, *Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program*, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).
30 See, by way of example, Utility Dive, "BQDM program demonstrates benefits of non-traditional utility investments", March 11, 2019.
31 Case 16-M-0411, In the Matter of Distributed System Implementation Plan Filings (issued March 9, 2017).
32 Case 15-E-0751 *et. al., In the Matter of the Value of Distributed Generation* (VDER Proceeding), Order on Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (VDER Order), pp. 13-17.
33 *Id.*, pp. 87-88.
34 *Id.*, pp. 89-91.
35 Case 14-M-0224, *Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs*, Order Authorizing Framework for Community Choice Aggregation Opt-Out Program (issued April 21, 2016).
36 Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment Infrastructure* (EV Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) (EV Order), pp. 27-32.
37 EV Proceeding, EV Order, pp. 76-81.
38 https://www.nysenate.gov/legislation/bills/2021/A3876 Please note that this bill is in the process of being amended to provide the Commission more flexibility in addressing make ready business models.
39 Case 22-E-0236, *Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging*, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued January 19, 2023).
40 *Infra*.

3.5 New York's focus on clean electricity

New York began to encourage the development of clean energy long before the CLCPA was enacted through a sequence of major policy decisions:

- The Commission created the Renewable Portfolio Standard (RPS)[41] in 2004 and the Energy Efficiency Portfolio Standard (EEPS)[42] in 2008. The RPS involved the NY State Energy Research and Development Authority (NYSERDA) issuing RFP solicitations for tranches of renewable resources.[43] The Commission revamped the RPS in 2009 stressing the need for more regular solicitations and established a goal of 30% renewable resources in New York State by 2015.[44]
- A Clean Energy Fund was established in 2016 to support a variety of NYSERDA led clean energy initiatives.[45] The Commission, in 2016 approved a Clean Energy Standard (CES) adopting a goal of 50% of electricity consumed in New York by 2030 would be generated by renewable energy sources.[46]
- As mentioned earlier, an emissions credit (ZEC) program was established as part of CES to recognize the value of nuclear generation.[47]

The Commission in 2018 adopted a goal to add 2,400 megawatts of offshore wind capacity in New York State by 2030.[48] NYSERDA would run the procurement process and utilities would pay for the offshore wind RECs, and NYSERDA contracted for 1,696 MW of offshore wind in October 2019.[49]

While New York increased its reliance on renewable generation by 1,440 MW (26 percent) to 7,028 MW between 2010 and 2019, these initiatives if successful have the potential to more than double this amount by 2030.

These efforts have continued since the passage of the CLCPA. The Commission issued an order in January 2022 addressing implications of offshore wind on the transmission grid of Long Island and NYC.[50] To facilitate achievement of the CLCPA goals the Commission has effectively made CES consistent with CLCPA requirements by: (1) permitting indexed REC bids for solicitations to enhance the finance ability of projects;[51] (2) adjusting the CES targets to meet the CLCPA targets;[52] and (3) directing NYSERDA to procure up to 3,000 MW of bundled transmission and renewable energy for the purpose of delivering it to New York City (Tier 4).[53] Contracts for 2,550 MW of Tier 4 projects were announced in late 2021.[54]

41 Case 03-E-0188, *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard* (RPS Proceeding), Order Regarding Retail Renewable Portfolio Standard (issued September 24, 2004) (RPS Order).

42 Case 07-M-0548, *Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard*, Order Establishing Energy Efficiency Portfolio Standard and Approving Programs (issued June 23, 2008).

43 RPS Proceeding, RPS Order, pp. 51-52; RPS Proceeding, Order Approving Implementation Plan, Adopting Clarifications, and Modifying Environmental Disclosure Program (issued April 14, 2005), pp. 13-26.

44 RPS Proceeding, Order Establishing New RPS Goal and Resolving Main Tier Issues (issued January 8, 2010) pp. 10-11.

45 Case 14-M-0094 *et. al., Proceeding on Motion of the Commission to Consider a Clean Energy Fund* (CEF Order), Order Authorizing the Clean Energy Fund Framework (issued January 21, 2016) (CEF Order).

46 Case 15-E-0302 *et. al., Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard* (CES Proceeding), Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Order), pp. 75-77.

47 CES Proceeding, CES Order, pp. 119-150.

48 Case 18-E-0071, *In the Matter of Offshore Wind Energy* (OSW Proceeding), Order Establishing Offshore Wind Standard and Framework for Phase 1 Procurement (issued July 12, 2018) pp. 15-21.

49 https://www.nyserda.ny.gov/-/media/Files/Programs/offshore-wind/osw-phase-1-fact-sheet.pdf

50 OSW Proceeding, Order on Power Grid Study Recommendations (issued January 20, 2022).

51 CES Proceeding, Order Modifying Tier 1 Renewable Procurements (issued January 1, 2020) pp. 13-26.

52 CES Proceeding, Order Adopting Modifications to the Clean Energy Standard (issued October 25, 2020) (CES Modification Order), pp. 1-2.

53 CES Proceeding, CES Modification Order, pp. 77-101.

54 https://www.governor.ny.gov/news/governor-hochul-announces-finalized-contracts-clean-path-ny-and-champlain-hudson-power-express

3.6 Recent focus on the future of the natural gas industry

The CLCPA's vision has profound implications for the state's gas utilities because the Act requires zero emissions from generation by 2040.[55] This is significant because natural gas is the primary fuel for electric generation.[56] The CLCPA's more general emission requirements are consistent with the State's emphasis on clean heating conversions from oil/natural gas to heat pumps and NYC's ban[57] on natural gas in new buildings. This is significant because 60 percent of residential homes in the State heat with natural gas.[58] All of this implies that gas sales will consistently decline over the next two decades. Further complicating the situation is that while it is unclear whether renewable natural gas (RNG) is permitted under the CLCPA,[59] the Act has language that gives the Commission some flexibility in implementing the specific gas generation targets to the extent that dispatchable renewable resources are not sufficiently available.[60]

Utilities have raised concerns regarding the risk implications of these policies in several rate cases and have made proposals to shorten the depreciation lives of their assets. The Commission thus far has not been sympathetic to these arguments.[61] Nevertheless, the simple fact is that reductions in gas sales will put upward pressure on rates to the point at which further rate increases will not be sustainable and assets will be stranded.[62] As described in the next section, these issues have yet to be resolved by the CAC scoping plan.

In fact, there are many details that will require extensive coordination between electric and natural gas utilities.[63] These details impact virtually every aspect of providing either electricity or natural service including the impact on supply planning, network planning (investments or retirements), and customer engagement. Customers, in particular, may have heard of prohibitions against new gas service but are generally unaware of the impacts (cost, convenience, etc.) on their homes and businesses of a potential requirement to convert from natural gas to electricity or perhaps to convert to a dual-fuel heat pump if that becomes a viable and preferred option.

The Commission, recognizing the long-term implications of the CLCPA's objectives for gas delivery utilities, issued an Order in May 2022 requiring each natural gas utility to develop long-term gas plans on a staggered schedule that consider the implications of electrification on gas operations over the next 20 years.[64] Thus far one utility, National Fuel Gas has filed an initial draft for public comment. This filing included alternative scenarios and a "recommended" plan that balanced the tradeoff between rate and other cost implications and GHG emissions reductions. The recommended plan takes a "bottoms-up" approach, as opposed to a "top-down" approach that is designed to align with the targets established by the CLCPA. However, the CLCPA did not establish targets by sector or for natural gas utilities within the gas utility sector. PSC Staff is currently leading a stakeholder engagement process that will lead to the filing of a "Final Plan" that the Commission may or may not approve. New York's other large gas utilities will be filing their long-term plans over the next year.

55 *Infra*.
56 NYSERDA document for 2021 available at: https://www.nyserda.ny.gov/about/publications/ea-reports-and-studies/patterns-and-trends
57 See news story at: https://www.reuters.com/markets/us/new-york-city-set-ban-natural-gas-new-buildings-2021-12-15/
58 EIA State Analysis available at: https://www.eia.gov/state/analysis.php?sid=NY
59 RNG would not emit carbon but would emit other GHGs. To date, most environmental advocates have opposed the use of RNG.
60 CLCPA, p. 17.
61 Case 20-G-0101, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Corning Natural Gas Corporation for Gas Service*, Order Establishing Rates and Rate Plan (issued May 19, 2021), pp. 27-31.
62 Consolidated Edison agreed as part of a 2019 rate case settlement to study the impact of accelerated depreciation on customer rates as a methodology to address stranded costs from declining throughput. May 2021, Case 19-E-0065
63 In December 2020, the Commonwealth of Massachusetts published a *Decarbonization Roadmap to achieve Net Zero by 2050*. The Department of Public Utilities is conducting a proceeding (DPU 20-80) that required the LDCs to retain an independent consultant to prepare a pathway analysis of alternative visions for the future of the natural gas industry. A draft report was issued on February 15, 2022 that evaluates five alternative pathways.
64 Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Order Adopting as Gas Planning Process (issued May 12, 2022) (Gas Order).

This case exposes the problem created by requiring the filing of long-term gas plans before sector specific targets are established. Perhaps recognizing this gap, the Commission issued a companion order establishing a new docket (Case 22-M-0149) that requires the State's gas utilities to jointly develop a pathways analysis showing how the state's gas utilities will as a whole move toward electrification over the next 20 years.[65] Work framing the initial scope of such a study is now underway.

3.7 Outcomes and tensions

The electrification effort required by the CLCPA will make New York a winter-peaking State. The size of the buildout of the transmission system owned by the electric utilities and subject to Commission regulation is still being assessed. Moreover, the CLCPA's vision has been adopted by decision makers based on assumptions about future resources that currently do not exist. The current summer peak in the State is about 32,000 MW and the winter peak is about 23,000 MW.[66] Given the expected electrification efforts the NYISO projects that "by 2040, the summer peak could be over 47,000 MW while the winter peak could be over 56,000 MW."[67] Given the CLCPA's requirements, the NYISO projects that under the CLCPA "the amount of dispatchable emission-free resources needed increases to over 32,000 MW in 2040, approximately 6,000 MW more than the total fossil-fueled generation fleet on the grid in 2021."[68] This is significant because as the NYISO notes, there is no commercially technology currently available that would support dispatchable emission-free resources.[69] While this should be a major concern, the NYISO CRP nonetheless seems to downplay this matter.

Since REV and the CES were instituted, the Commission has placed emphasis on assuring that the low- and moderate-income customers, environmental justice areas, and disadvantaged communities share in the benefits of the transition to a clean energy future, rather than being left behind to bear its costs. Thus, the Commission has required that 20 percent of the EV Make-Ready Program budget[70] and 20% of the energy efficiency budget[71] be allocated to low-income customers or disadvantaged communities. Affordability and environmental justice are also stressed in the CLCPA. The CLCPA directs state agencies to implement the Act in a manner designed to deliver 40 percent of its benefits to disadvantaged communities and requires that actual benefits to these communities be no less than 35 percent of the Act's total benefits.[72] It is unclear how the benefits will be measured and what the consequences are of not meeting the Act's requirement.

65 Case 22-M-0149, *In the Matter of Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act*, (also issued May 12, 2022)
66 NYISO Comprehensive Reliability Plan 2021-2030 (issued December 2, 2021) (CRP), p.38.
67 CRP, p. 39.
68 *Id.*, p.47.
69 *Id.*, p. 48.
70 EV Proceeding, EV Order, p. 46.
71 New EE Proceeding, New EE Order, p. 4.
72 CLCPA, p. 16.

The focus on clean energy highlights the potential conflicts between New York's ambitions and the goal of maintaining an affordable and reliable energy supply. Since 2016, the Commission has approved well over $15 billion of collections from electric utility customers to support energy efficiency,[73] electric vehicles,[74] offshore wind,[75] a variety of other activities supporting the development of renewable resources in the CES proceeding,[76] and bundled clean energy/transmission for New York City (Tier 4).[77] In doing so, the Commission did not seriously address the impact on customers of this increase in utility collections in any of the associated Orders. It appears that the CLCPA decision structure represents the culmination of a process that has increasingly marginalized the importance of the Commission's primary responsibility under the Public Service Law: safe and reliable service at a reasonable cost to consumers. On the other hand, the costs of these initiatives per New York State resident is not that significant if the costs are recovered over a period of years. It remains to be seen whether there will be a future retrenchment of New York's clean energy agenda should the State's economy experience a downturn or the burden on customers be deemed excessive.

New York's electric utilities have expressed concerns about costs in the past.[78] While such concerns may have had traction in 2010, they have been largely ignored since the CES Order in 2016. The unstated message that many utilities feel based on their conversations with state decisionmakers is that mentioning the cost of these programs will not lead to positive outcomes when rate cases are filed. Thus, there has been little emphasis by the utilities on the cost of CES programs and the implications of the CLCPA.

73 New EE Proceeding, New EE Order, Appendix A shows that the total budget for EE through 2025 is about $900 million. This does not include PSEG Long Island's budget on behalf of the Long Island Power Authority. This budget amount will likely be increased in 2022 in order to better comply with the CLCPA goals. The amount authorized for the 2025-30 period will be an even larger amount.

74 EV Proceeding, EV Order, a budget of $582 million was established for the Make-Ready Program through 2025 (p. 68). This amount will be reviewed later this year as Con Edison's budget is almost fully allocated to projects.

75 OSW Proceeding: New York's Joint Utilities (all major investor owned electric and gas utilities) estimated that the capital cost associated with wind project obtained in the first procurement could be in the $4.0 to $4.5 billion range before considering capital costs associated with land-based system upgrades and ongoing operation and maintenance expenses. Costs for a second procurement would also be significant. (Joint Utilities Comments on Offshore Wind Regulatory Program (dated June 4, 2018) pp. 2-3.

76 CEF Proceeding: The Joint Utilities estimate that the total cost of the CEF program through 2025 will be $7.4 billion (Joint Utilities' Initial Comments on NYSERDA's Petition Regarding Clean Energy Fund Triennial Review and Authorization for Optimization of the CEF Portfolio (dated April 5, 2021), pp. 7-8. (Joint Utilities Comments on Offshore Wind Regulatory Program (dated June 4, 2018) pp. 2-3.

77 The two projects selected under the CES Modification Order will, on the basis of Concentric work done for two private clients, have capital costs exceeding $6.0 billion.

78 *See e.g.,* Case 14-M-0094 *et. al., Proceeding on Motion of the Commission to Consider a Clean Energy Fund*, Initial Comments of the Joint Utilities on the Clean Energy Fund Information Supplement (filed August 14, 2015), pp. 3-5, 13-15.

4 Policy change processes and innovation

Much of the industry commentary during the initial few years of the REV proceeding focused on the relatively (at that time and in the United States) radical changes to the electricity distribution business model. Changes to policy making and regulatory processes have proven to be as significant and long-lasting as the business model issues themselves. While the focus of REV was the electric industry there has been an increased Commission focus on the future of the natural gas industry, driven by a focus on electrifying building heating and cooling loads which is considered by New York as a primary pathway to achievement of the GHG emissions reduction targets.

4.1 Policy and regulatory process themes

There are a few sustained themes that emerge from examining the period leading up to the initiation of the REV proceeding, the subsequent "REV and related proceedings" period, and continuing into the "CLCPA compliance and implementation period". These themes include:

- Reliance on paper proceedings that included many of the following steps: an initial Staff white paper inviting comments and often a round of reply comments, one or more workshops organized by Staff with panel presentations from the utilities and other stakeholders, culminating with a policy order.
- Heavy reliance on ex-parte communications (New York has no rules preventing such communications) and the lack of evidentiary hearings has weakened the transparency of the decision-making process.
- Impactful participation of a growing number of external stakeholders, particularly environmental organizations in the policy making and regulatory processes.
- Collaboration among the investor-owned utilities in an effort to speak with one voice to the extent possible in both informal communications with Commission Staff and in joint filings on policy and implementation matters.
- Emergence of a collaborative relationship between NYSERDA and the PSC, particularly on implementation issues (e.g., low-income energy efficiency and heat pump implementation) and the development of energy policy white papers; and
- Reliance on three-year utility rate case settlements, where Staff has maximum leverage to refine and implement ratemaking and incentive precedent, approve utility enabling investments and cost-recovery, and direct utility-specific studies that will inform CLCPA implementation efforts.

These process steps did not make the issues any less complex – and in many instances – helped reveal the interconnectedness of policy and implementation issues thus adding to the challenge of developing coherent, integrated policies. Policy orders usually led to the extension of cases for further policy refinement or implementation requirements – and on occasion, new policy cases. Moreover, none of these proceedings have had statutory deadlines, often leading to long "quiet" periods between final comments and the issuance of an order. These quiet periods provide time for an over-burdened Staff to draft and refine important orders. They also provide an opportunity for extra-judicial conversations between the Commission and the Administration as well as outside special interests. As noted, the New York governor's administration has exercised outsized influence over many energy industry restructuring decisions – as compared to other US jurisdictions, opening the door for stakeholders to engage directly with the Administration to influence a Commission order. While, in retrospect, it is difficult to even imagine addressing each of these issues through "litigated" proceedings with filed testimony and hearings, a process based on fact-gathering and open debate in public stakeholder processes would have been significantly more transparent.[79]

The 2014 REV proceeding remains an open and active proceeding to this day; however, at least eight significant new policy "arms" have been initiated making it challenging for all parties to participate effectively. Each of the investor-owned utilities, for example, have dozens of their top personnel devoted to participation in policy proceedings at any point in time.

79 Fact-gathering and open debate in public stakeholder processes would be significantly more transparent.

4.2 The launch of Reforming the Energy Vision proceeding

The Commission's initiating order in Case 14-M-0101, issued after lengthy vetting by the Governor's office,[80] called for, "policy determinations to be informed by participation by all stakeholders in collaborative discussions, based upon the Report accompanying this Order, as well as any subsequent proposals."[81] The Order indicated that "parties will have opportunities to file comments on Staff proposals and to fully present their views, including at technical conferences or otherwise before the Commission."[82] The Commission established target dates for the policy orders to address business model issues identified in the accompanying Staff report (Track 1) by the end of 2014 and regulatory changes and ratemaking issues (Track 2) by the first quarter of 2015, with the latter timed to accommodate a second Staff Report.[83]

The Track 1 order was followed by facilitated stakeholder working group (the Market Design and Platform Technology Working Group (MDPT)) discussions of several technical issues. This group brought together utilities, third party vendors, and other stakeholders, producing a report on August 17, 2015.[84] The report notes that, "every effort has been made to capture key themes and fairly represent multiple perspectives",[85] "the material contained in this report does not necessarily reflect consensus views of MDPT Working Group members or advisors",[86] and finally that, "the final report is intended to be an input for the NY Department of Public Service's consideration and does not represent Staff or the PSC's views."[87] The initial hope appeared to be that subject matter experts from organizations with competing strategic and economic interests would be able to resolve technical issues in this type of forum. Grand collaborative exercises were abandoned after this initial attempt leaving technical issues to be resolved through Commission action. This is a logical outcome as technical issues cannot be separated from economic interests that differ among key stakeholders, particularly utilities and third parties that want access to utility customers and specific rules to support their business models.

However, the MDPT exercise did make it clear that a new set of stakeholders, representing competitive firms from all over the country with business opportunities created by REV (and similar models if adopted by other jurisdictions), were going to be active participants in REV proceedings. These new participant stakeholders (e.g., DER owners, developers, clean energy advocates, and low-income customer advocates) became active in REV and its many subsidiary proceedings.[88] While this drew attention to New York as a leader with respect to the future structure of electric markets, it also revealed the complexities of the new structure given the needs of, and business models used by, a wide array of new market entrants with divergent interests. This presented a challenge to Staff and Commissioners who are often much more comfortable assessing and issuing opinions on regulatory matters than effectively establishing the rules of the road for activities relying on the emergence of a viable (financeable) competitive market to deliver energy services and associated value to consumers.[89]

To facilitate progress, Staff issued several reports that did not simply identify and define the issues to be resolved; they presented the Commission's vision and articulated a proposal for stakeholders to react to. This is an effective process for a regulatory agency that has a clear vision and a developed concept of how it believes the vision should be implemented. Stakeholders have an opportunity to offer their perspectives through public means: informal stakeholder sessions and filed comments. The fact that the Commission has no formal ex-parte rules also enabled more private communications between the utilities and Commission Staff.[90] However, it also invites direct communications between intervenors and Commission Staff.

80 Conversations with former Commission employees.
81 REV Proceeding, Initiating Order, p. 5.
82 *Id.*, p. 6.
83 The Commission issued a Track 1 order on February 26, 2015, and a Track 2 Order on May 19, 2016.
84 Report of the Market Design and Platform Technology Working Group, August 17, 2015.
85 REV Proceeding, Report of the Market Design and Platform Technology Working Group.
86 *Id.*, p. 2.
87 *Id.*
88 A list of the 230 parties in this proceeding may be found here: https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&CaseSearch=Search
89 For example, competitive suppliers require customer and system data to market to and serve end-use customers. However, a start-up business may not be in a position to invest in cyber and data security capabilities or acquire insurance that covers the consequences of a breach – two demands that utilities and Staff are likely to support.
90 An alternative for jurisdictions with ex-parte rules could be for the regulatory body to suspend the rules for specific inquiries.

A third process innovation was a request by the Chair that the large investor-owned utilities submit a single set of comments rather than individual comments by each utility as had been the typical practice for generic proceedings. The "Joint Utilities of New York" have been filing joint comments in all REV and related proceedings since 2014, with supplemental comments filed by an individual utility on a limited number of occasions. This innovation has been efficient from the view of the PSC Staff and other active participants and has enabled the utilities to better align their positions before filings are made.

4.3 REV and related initiatives, increasing collaboration

As leaders of the REV initiative, Commission Chair Audrey Zibelman and the Governor's "energy czar", Richard Kauffman, recognized that a new business model, enabled by emerging technology, required innovation. The Commission issued an order on December 12, 2014, to explicitly encourage utilities to work with third parties to develop "demonstration projects" and invited the utilities to propose cost recovery mechanisms. The Order observed that, "demonstration projects will be an important step in implementing the expected REV policy changes and will inform decisions with respect to developing Distributed System Platform (DSP) functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective integration of DER."[91] An accompanying memorandum offered a set of criteria that would cause the Commission to look favorably on such proposals.[92] During this same period (2014-2015), NYSERDA established a $5 billion Clean Energy Fund and the NY Green Bank to finance private investment in renewable energy and energy efficiency projects. New York also established NY Prize, a $40 million community microgrid competition.

Over the course of the following few years, the Cuomo administration improved the coordination between the Commission and NYSERDA, as both organizations reported to Richard Kauffman. A few years prior to this arrangement, NYSERDA and the Commission acted as independent entities and Commission decisions were not always consistent with NYSERDA's clean energy agenda due to concerns about the cost of electricity to consumers (utility customers pay for NYSERDA's budget in their rates). This led to frequent disagreements between the two entities that often had to be resolved by the Governor's Office.

New York's increasing focus on clean energy has contributed to a need for greater alignment and collaboration between the Commission and NYSERDA, allowing the Commission to rely on competencies and experience that existed at NYSERDA without having to close this gap by developing or hiring new Staff. This increased collaboration was evident when the Commission issued its CES Order in 2016, beginning a productive period of collaboration that has resulted in jointly authored major white papers including one on energy efficiency.[93] More recently, NYSERDA with Commission Staff input issued a roadmap for extending the State's solar energy goal from 6 GW to 10 GW by 2030.[94] While the Commission retains the ultimate power to authorize programs and associated spending, those programs now reflect the combined thinking of two organizations, while presenting a shared perspective to external stakeholders. This collaboration has developed to the point that Commission Staff, NYSERDA, and the utilities are in the process of working together to address the energy efficiency needs of low- and moderate-income customers and the promotion of heat pumps as a substitute for fossil-based hearing.[95]

91 Notice Encouraging Development of Demonstration Project Proposals, December 12, 2014.
92 Memorandum and Resolution on Demonstration Projects, Case 14-M-0101, December 12, 2014, Pages 6-10.
93 Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={205DF967-399B-4AA3-87B7-152C8785C723}
94 Available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4C42AAFF-0EB9-4890-AA0D-21C70B088F4B}
95 The New EE Order required the utilities and NYSERDA to work together in ten specific areas including the development and actual implementation of Clean Heat and LMI Implementation plans. Staff was also directed to provide the utilities and NYSERDA guidance on these matters.

The Chair of the Commission and high-level advisors at the Commission serve at the Governor's pleasure with many of them lacking civil service protection in the event they are dismissed.[96] In theory this supports collaboration among the Commission and NYSERDA, but it has evolved in a manner that leaves an impression that the Commission does not have sufficient independence to execute its judicial responsibilities including arriving at a fair balance between customers and shareholders. The historical experience, characterized by regular meetings and other communications between the Chair and administration has evolved over the past several years to the point whereby the Commission generally requires approval for significant orders by the Governor's Office.[97] One might argue that the balance has tipped too far, particularly as it relates to orders that depend on subject matter expertise and familiarity with the proceeding record.

An example of this concern relates to the pressure the Governor's Office exerted on the Commission to make solar available to those who could not put it on their roof or did not want to do so. By creating separate Remote Net-metering, Community Choice Aggregation, and Community Distributed Generation programs and requiring that all billing be done by the utility, the Commission created a number of complex program choices for customers to understand as well as complex tariff/collection issues for the utilities. The end result has been customer confusion/complaints and delays in the full roll-out of complete programs. As a result, the Commission is currently evaluating simpler approaches.

4.4 CLCPA legislation and scoping plan

The CLCPA was the first major energy legislation in 30 years. Policy initiatives, including restructuring of generation and establishment of competitive retail choice were driven by the Commission working with the governor's office. The lack of legislation was not for lack of trying but rather due to one party not controlling the governorship and the two legislative bodies (Assembly and Senate). Even where there has been legislative control of both bodies by the Governor's party, differences between upstate and downstate members frequently contributed to impasses with respect to energy legislation.

The CLCPA, by virtue of establishing statutory mandated targets, is a policymaking game changer. Prior to the CLCPA, the Governor, or NYSERDA on his behalf, issued public pronouncements that related to GHG goals, renewable generation goals, or goals that applied to specified programs that formed the basis for subsequent PSC policy and implementation plan proceedings. It is worth noting these legislative actions resulted from pressure brought to bear by a governor seeking to establish statutory mandates to achieve his policy priorities, rather than initiated by the legislature.

The CLCPA did not dictate a precise pathway to achieve these mandates. Rather, the law established a CAC tasked with developing a "scoping plan" to achieve statutory requirements and place New York on a path toward carbon neutrality. A 304-page draft scoping plan was issued on December 21, 2021; a final plan was issued on December 19, 2022.

The final Scoping Plan provides guidance for decarbonization of all sectors of the New York economy including the utility and transportation sectors. It observes that every sector will require a substantial transformation and concludes that the 2050 targets can be met. Energy efficiency and extensive electrification of all end-uses are required. The Scoping Plan assigns numerous implementation responsibilities to the PSC and NYSERDA. It places significant emphasis on an imperative to address the needs of "Disadvantaged Communities" and climate justice objectives, directing that at least 35% of spending on energy efficiency and clean energy be directed to Disadvantaged Communities.

96 The current Executive Deputy to the Chair worked in the Governor's Office for a decade.
97 Conversations with former Commission employees.

The transformation of the electricity sector incorporates a reliance on large scale renewables, modernization of the electric grid, and investments in storage and other dispatchable energy technologies. The Scoping Plan calls for a "strategic downsizing of the gas system" and the coordinated gas system transition plan:

> To ensure grid reliability needs are met, ensure the transition is completed in parallel with the New York Independent System Operator (NYISO) Reliability Needs Assessment. This should include a detailed, strategic, and coordinated approach to optimization of the electric and gas systems, and that any contracting of the gas system considers end-use customers who are highly reliant on gas, economic impacts, feasible alternatives, and growth in the power generation sector with electrification.[98]

Although achieving the CLCPA's goals depends critically on actions to be taken by utilities under the direction and oversight of the PSC, the ability of the utilities to influence the scoping plan has been limited to this point. The Commission, in response to the CLCPA and through its oversight and regulation of New York's investor-owned electric and natural gas utilities, is in a position to direct the utilities to take actions that achieve the legislative mandates. The Commission may resort to market design, price signals and tariff options, but at the end of the day they are likely to rely on prescriptive policy approaches to meet the goals given the establishment of mandates as statutory requirements. Economic principles may remain relevant to the extent that they do not interfere with the achievement of environmental targets. However, determining decarbonization pathways that will deliver safe, affordable, reliable, and resilient services while meeting statutory environmental targets will be a very difficult task.

Put another way, with the passage of the CLCPA, it may be the intent of the State to have the Commission apply its regulatory leverage over the state's utilities to meet environmental targets and related policy goals (e.g., utility-backed contracts for large-scale renewables (LSRs), environmental justice for disadvantaged communities). The amount of discretion the Commission will have is unclear at this time, and final decisions are subject to appeal if parties can make a case that provisions of orders are inconsistent with the CLCPA . This is important because of an expressed concern by regulatory experts that a number of elements in the Scoping Plan are unrealistic and/or infeasible from a regulatory and customer viewpoint.

98 Final Scoping Plan, page 361.

5 Lessons for the future

Finding 1: New York's approach to energy policy has evolved from a focus on promoting clean energy when economically efficient to a "planning-centric" model that is rationalized based on the need to comply with the CLCPA and achieve mandated targets. This effort began with the CAC scoping plan but there are clear indications that utility planning will be subject to new demands. Diverse and in many cases diametrically opposed views from environmental organizations and other stakeholders will bring scrutiny of forecasts, debates over planning methodologies and modeling assumptions, and litigation of proposed investment decisions.

Finding 2: The CLCPA final report supporting electrification and the Commission's requirement for long-term gas plan filings over a 20-year time horizon highlight a fundamental challenge due to the separate planning requirements for electric (DSIPs) and gas (Long-Term Plans) filings. The Final Scoping Plan identifies the need for joint energy planning. Massachusetts and California are also recognizing this need. However, there are several challenges that will need to be addressed by policy makers in order to implement joint energy planning, including the prevalence of overlapping service areas between unaffiliated electric and natural gas distribution companies.

Finding 3: New York is currently on what appears to be an "all-electrification" path with minimal consideration thus far of renewable natural gas or hydrogen as potential heating/industrial fuels. Although the CAC scoping plan does not present a specific proposal for a phase-out the natural gas industry, the report seems inclined toward this outcome. The individual gas utility long-term gas plans and planned statewide gas pathways study, and upcoming rate case decisions will test the validity of this path as they reveal the tradeoffs between reduced reliance on natural gas for building heating and cooling (and associated declines in throughput) and the impacts on utility rates and other costs.

Finding 4: There is some potential for natural gas to continue to play an important role as questions are being raised regarding a continuing role for natural gas in delivering resilience for the "whole energy system" when considering gas and electricity together. Among the issues yet to be resolved are whether heat pumps coupled with a gas heat backup will help moderate a winter-peaking electric sector.

Finding 5: The Commission's reliance on paper proceedings has served New York well to date and is expected to continue in the future. This process has been used to address not only technical issues but also fundamental policy determinations commencing with a Commission Staff white paper followed by comments from interested parties to provide the Commission a decisional record.

Finding 6: The transition to a clean energy future requires strategic direction that can be set by the governor under the New York model, while exercising authority not only over the energy office (NYSERDA) but over policy established by orders issued by the regulatory commission. This may be effective from a leadership (and election) perspective, but the lack of transparency within New York with respect to how energy policy and operational decisions are made and what evidence is brought to bear to decide important societal issues is not ideal.

Finding 7: There is also a direct conflict between the desire for innovation and the prospect of increasing involvement in utility decisions, large and small. Under these circumstances, it is not clear how the policy and regulatory model will be able to realize efficiency gains that are essential to keeping energy affordable for all customer segments.

Finding 8: Ironically, a command-and-control regulatory model, without market and compliance mechanisms, justified by the need to meet legislative mandates, may make it harder to achieve the targets at a cost that will be acceptable to energy customers and the broader citizenry.

Finding 9: A more transparent approach to examining alternative pathways and market mechanisms to support a decarbonization future would be a good start. This requires open utility planning processes supplemented by facilitated collaboratives where all stakeholders would have an opportunity to engage earlier in the decision-making process. Ultimately, from a process perspective, key decisions for Canadian jurisdictions come down to:

- Who has responsibility for setting the targets and goals for achieving a clean energy future?
- How transparent should decision-making be?
- What is the appropriate balance between reliance on market forces (including carbon markets/pricing) versus command-and-control regulation?

uOttawa

POSITIVE ENERGY

CASE STUDY 3: WESTERN AUSTRALIA

Andrew Pickford,
Faculty Affiliate, Positive Energy

Table of contents

1 Introduction

This case study focuses on the Australian state of Western Australia and its experience with energy reform and decarbonisation.[1] Western Australia is particularly relevant for several Canadian electric and gas utilities due to the following factors: physically islanded from the larger national energy market resulting in earlier challenges integrating various renewables; significant domestic gas production and domestic consumption; extensive use of gas in the electricity sector; predominance of government utilities in terms of electricity retailing and generation; high penetration of renewables in the form of residential solar; and active plans to introduce renewable hydrogen into the gas network, with blending up to 10 percent and associated technical, regulatory and legislative reforms underway.

From a constitutional and legal perspective, Western Australia (as well as other Australian states) is relevant level of analysis. It should also be noted that local governments have little influence over the energy sector and the federal government involvement has been a recent phenomenon. While Canada has followed its own development pattern, the experience is broadly similar.

This report draws on a series of interviews with senior decision makers across the political spectrum as well as with industry executives in public and private utilities. The insights have been distilled into 18 key findings which summarise lessons from the state's decarbonisation experience. The primary focus of the detailed case study is on the pivotal 2019-2021 period which, according to a range of industry participants, has generated the most significant changes since the early 2000s. There is also a review of the impact of natural gas networks on ambitions to create a green hydrogen export sector, and a short review of national gas networks. A postscript covers the period 2022-2023 when several decarbonisation related policies were implemented and a new, centre-left federal government came into power and accelerated federal changes. These policies are in line with the analysis in the case study and confirm the key themes relating to the challenges of transforming legacy power systems.

Rather than presenting a technical study, of which there are many publicly available,[2] this report aims to convey the views and experiences of insiders who have dealt with similar institutional tensions, provincial-federal dynamics and shareholder expectations. In general, private utilities favour industry associations to lead policy debates and have different approaches to Crown-owned utilities which interact directly with government.

1 Energy in this paper refers to the midstream and downstream components of the gas and electricity sector and associated markets. While LNG falls outside this definition, it is sometimes included as the relatively large size of this export sector influences the approach to energy policy and decarbonisation.

2 The peak policy entity within the Western Australian government, Energy Policy WA, has produced a range of studies, reports and technical analysis associated with energy reform. These can be found on the following website: https://www.wa.gov.au/organisation/energy-policy-wa. The system operator, Australian Energy Market Operator (AEMO), has similarly conducted a range of studies and analysis. While a national entity, the work that it undertakes on Western Australia can be found at the following site https://aemo.com.au/en/energy-systems/gas/gas-retail-markets/procedures-policies-and-guides/western-australia. This Case Study refers to several Energy Policy WA and AEMO reports which are all in the public realm.

2 Context and background

This section outlines the context and background for the reform of the Western Australian energy sector.

2.1 Legal and constitutional settings

Australia is a constitutional monarchy with power divided between state and national levels of government. Local, or municipal, governments exist as a subset of the respective states, but they do not hold constitutional status. Energy policy was traditionally the preserve of state governments, which historically owned integrated energy utilities. However, the creation of a national energy market, interconnection of state grids, and the emergence of climate change is increasingly pushing energy policy into the national arena.

Prior to the rise of environmental concerns, which accelerated after 2000, there was a bi-partisan consensus to develop cheap, base load electricity for industrial users and consumers. This was done through government owned utilities and is most obvious with the brown coal in the La Trobe Valley of Victoria, black coal in the Hunter of New South Wales and North West Shelf natural gas in Western Australia. In the case of Western Australia, the traditional commodity-based export orientation of the economy was a long running point of tension with the east coast manufacturing base.

There was a significant clash between Western Australia and Canberra during the 1970s over the development of an LNG export capability. This included a constitutional conflict that came to a head over a proposed natural gas pipeline and what would be a de facto nationalisation of a major natural gas field. The incident created long standing tensions and animosities which had parallels to the response by Alberta to Prime Minister Pierre Trudeau's National Energy Program.

As part of national competition and productivity reforms, efforts to create a national energy market began in the 1980s and accelerated from the 1990s. Given that Western Australia's electricity and gas grids are physically separated, it continued with its own approach to energy policy. The integration of state-based systems to form a national energy market was not without challenges. A book written on the process was aptly titled: 'Warring Tribes'. Over time, interactions between states focused more on technical matters. Intergovernmental discussions on energy were primarily facilitated by the Council of Australian Governments (COAG) Energy Council, which included state and federal energy ministers. However, as part of the COVID-19 response, COAG was scrapped and formally replaced by the Energy National Cabinet Reform Committee and the Energy Ministers' Meeting in May 2020.

2.2 Climate change policy and priorities

Western Australia's involvement in energy and climate change policy debates is largely caused by differences with Canberra, rather than divisions within the state itself. For example, the development of the state's LNG sector is largely bipartisan, with centre-left and centre-right parties in favour of its expansion. Similarly, the regulation and administration of the electricity and gas sector has largely been a matter of technical responses to generation shifts, fuel costs and decarbonisation challenges.

Western Australia was relatively late (compared to other states) setting an emissions reduction target for 2030. During the study, interviews indicated that there were ongoing discussions within the Crown utilities and ministerial offices on the introduction of a 2030 target. In an interview with a senior decision maker, the delay in settling a 2030 target was attributed to electoral issues associated with the Collie coal mining and electricity generation region. A formal 2030 policy triggers a quantifiable cost on the generators which would also crystallise the end date of operations. The Crown utility and government approach to the transition of this region from coal mining to new industries will be covered later in this report.

By June 2022 an internal position was clarified, and the state government signalled its intent to decarbonise the South West Interconnected System (SWIS) and plans to retire the state-owned (Crown) coal power stations by 2030 and not commission any new state-owned gas-fired power stations after 2030 and instead focus on renewable generation and storage.

Category	Western Australia	Australia
2030 Climate change position	Legislation expected by the end of 2023 to formalise aim to reduce Government emissions by 80 per cent below 2020 levels by 2030[3]	A 43 percent reduction of emissions below 2005 levels by 2030
2050 Climate change position	Net zero by 2050	Net zero by 2050
Climate change legislation	*Western Australian Climate Policy (legislation pending)*	*Climate Change Act 2022*

The below table outlines the most recent break down of net emissions in Western Australia and the change between 2005 and 2019.[4] While the economy has expanded during this period, the key theme for emissions has been a major expansion of the LNG sector which has increased fugitive emissions with reductions in agriculture and land use practices offsetting much of this growth.

GREENHOUSE GAS SOURCE AND SINK CATEGORIES	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Change from 2005 to latest reported year
													%
Total (net emissions)	80,601	84,914	82,821	73,657	74,842	78,596	76,684	80,041	84,360	81,327	85,808	91,852	**21%**
1. Energy	**53,051**	**57,243**	**56,758**	**59,584**	**62,217**	**66,621**	**67,680**	**68,237**	**71,968**	**78,282**	**82,456**	**84,337**	**67%**
A. Fuel combustion (sectoral approach)	48,723	53,156	51,755	55,051	56,857	60,789	62,289	62,497	65,233	68,087	70,211	71,487	**53%**
1. Energy industries	22,970	26,393	25,607	27,768	27,306	28,539	28,570	30,069	31,843	33,772	35,331	36,465	**62%**
2. Manufacturing industries and construction	12,234	13,018	12,126	12,860	14,267	16,565	17,593	15,834	15,751	16,098	16,639	16,814	**46%**
3. Transport	11,171	11,165	11,351	11,663	12,309	12,670	13,076	13,348	14,224	14,815	14,823	14,899	**45%**
4. Other sectors	2,348	2,580	2,672	2,761	2,976	3,015	3,051	3,247	3,415	3,401	3,419	3,309	**34%**
B. Fugitive emissions from fuels	4,328	4,088	5,004	4,533	5,360	5,831	5,392	5,739	6,736	10,195	12,245	12,850	**246%**
2. Industrial Processes	**4,708**	**4,810**	**5,369**	**5,156**	**5,260**	**4,578**	**4,675**	**4,678**	**4,530**	**4,607**	**4,679**	**4,344**	**13%**
3. Agriculture	**9,772**	**9,831**	**9,730**	**8,748**	**9,223**	**9,003**	**9,697**	**9,878**	**9,890**	**9,997**	**9,771**	**9,874**	**-14%**
4. Land Use, Land-Use Change and Forestry	**11,366**	**11,340**	**8,938**	**- 1,880**	**- 3,836**	**- 3,554**	**- 7,288**	**- 4,580**	**- 4,109**	**- 13,506**	**- 12,908**	**- 8,606**	**-200%**
5. Waste	**1,703**	**1,689**	**2,026**	**2,049**	**1,978**	**1,947**	**1,920**	**1,828**	**2,081**	**1,947**	**1,810**	**1,903**	**18%**
Total CO2 equivalent emissions with land use, land-use change and forestry	**80,601**	**84,914**	**82,821**	**73,657**	**74,842**	**78,596**	**76,684**	**80,041**	**84,360**	**81,327**	**85,808**	**91,852**	**21%**

Greenhouse gas emissions (ktCO2-e), State and territorial GHG inventories 2019, Western Australia.

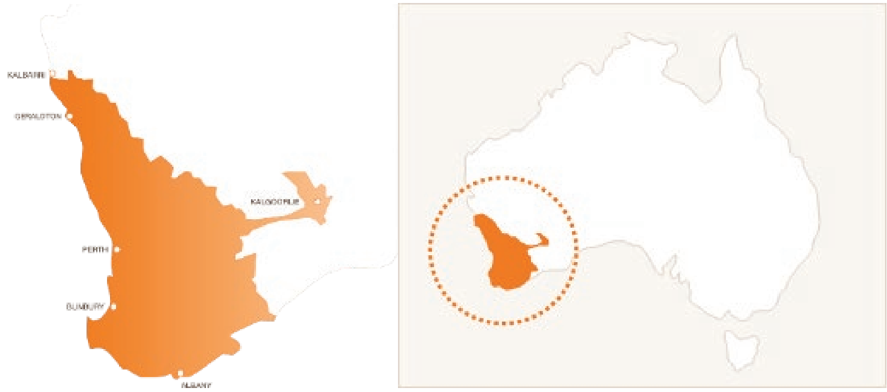
2.3 Key features of energy sector

The Western Australian stationary energy sector is concentrated in the islanded South West Interconnected System (SWIS) where the Wholesale Electricity Market (WEM) operates. Natural gas is primarily extracted offshore in the north-west of the state. Large volumes are exported as Liquified Natural Gas to Asian markets. Domestic natural use is predominantly in the south-west of the state, although it is commonly used in mining operations. The mild Mediterranean climate and long periods of sunshine is particularly favourable to solar power. The very mild winters, rarely dipping below 5 degrees centigrade, mean that there is a light heating load.

3 https://www.mediastatements.wa.gov.au/Pages/McGowan/2023/01/McGowan-Government-to-introduce-climate-change-legislation.aspx

4 For full data sets and definitions see: https://www.industry.gov.au/data-and-publications/national-greenhouse-accounts-2019/state-and-territory-greenhouse-gas-inventories-data-tables-and-methodology#download-the-data-tables.

Western Australia's South West Interconnected System.[5]



The SWIS is notable for the following features: over 7,800 km of transmission lines (customer base is dispersed area); the WEM supplies about 18 terawatt hours of electricity each year; there are more than one million customers; there are 5,798 megawatts of registered generation capacity (a capacity market); and a traditional 'Summer peaking system', with peak demand around 4,000 MW and average demand around 2,000 MW.

The WEM was traditionally overwhelmingly dominated by natural gas and coal. There is no nuclear power or hydropower due to government policy as well as the dry, arid climate. In 2021, the Australian Energy Market Operator recorded the following overall WEM annual electricity generation mix.[6] While the State Government has undertaken a whole of system plan, it produced four possible scenarios. In 2022, there was not an official outlook of electricity generation for the next decade. (See discussion below and finding 6).

Fuel source	Mix
Coal	43 percent
Natural gas	34 percent
Wind	19 percent
Other (includes solar)	2.9 percent

A key development of the past decade has been the rapid deployment of residential solar and large-scale wind generation. This has accelerated the shutdown of legacy (and old) coal generation. However, as an islanded grid, there are associated challenges with frequency, load control and system balancing. In the past decade, the deployment of residential solar (initially stimulated by generous feed in tariffs) has caused a duck curve in demand, which would be comparable to California, but on a much smaller scale. For the last two decades, a late afternoon peak in the heat of summer months was the key concern. However, from around 2018, the managing of this peak demand has become less challenging than managing minimum net grid demand. On January 4, 2020, a minimum demand of 1,138 megawatts was recorded. An estimated 896 megawatts of PV generation had displaced the underlying demand. The system security threshold minimum of 700 megawatts has been noted as a red line by the market operator. If this trend continues, load shedding will need to occur.

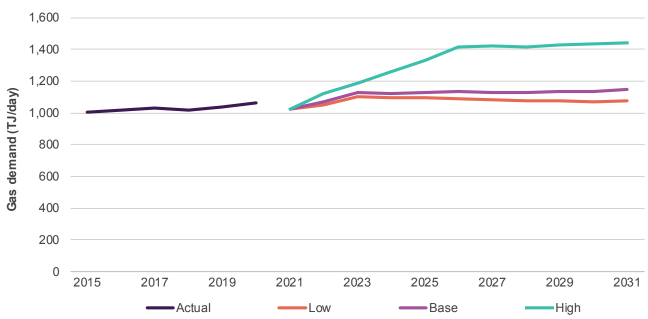
5 Image extracted from Western Power, a government-owned electricity transmission and distribution utility https://www.westernpower.com.au/about/what-we-do/

6 This does not include the 400,000 WA homes and businesses, around 30 per cent, which now have rooftop solar. In 2021, rooftop solar generation has supplied up to 64 percent of instantaneous energy output on the system.

The important, non-technical matters influencing policies include voter sensitivities over the continuity of air conditioning in January (akin to heating in Canada in the same months); electricity prices and further deployment of residential solar; and the expected rollout of EVs and batteries. The structure and ownership pattern of utilities has put the Western Australian government in a challenging position when responding to accelerated decarbonisation and voter expectations. Like some Canadian provinces, the direct ownership of utilities with private sector involvement in parts of the energy supply chain has complicated the emphasis on electrification and attempts to move towards green hydrogen. The below, high-level structure of the Western Australian energy sector divides the sector by ownership. While electricity is predominantly public and gas is predominantly private, the two are interlinked. As the system evolves, it is quite possible that the two will become more integrated. A domestic hydrogen market would further complicate this chart, as a large gas exporter may end up being a domestic hydrogen retailer.

It would be difficult to overstate the importance and role of natural gas in the Western Australian economy. In analysis of the outlook for natural gas demand, several unique features which influence the dynamics of the local market should be noted.[7] The below data published by the Australian Energy Market Operator is extracted from their annual Western Australian Gas Statement of Opportunities outlines a range of expected forecasts for domestic gas demand.

Domestic Gas Demand, Actual Data From 2014 to 2019 and Forecasts Under Three Growth Scenarios From 2022 to 2031



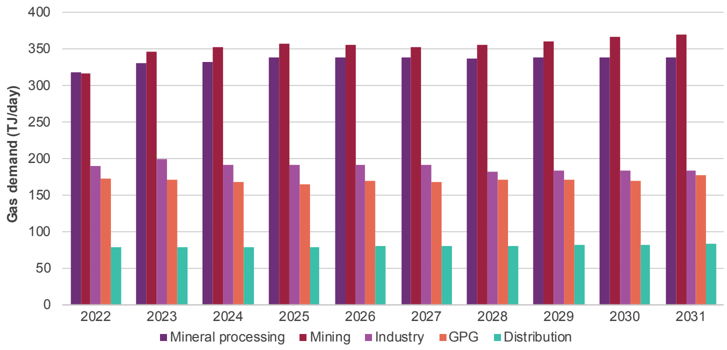
Scenario	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Actual	1,002	1,020	1,031	1,017	1,039	1,060											
Low							1,021	1,049	1,101	1,092	1,092	1,091	1,085	1,074	1,074	1,070	1,073
Base							1,022	1,071	1,125	1,122	1,129	1,133	1,129	1,127	1,134	1,137	1,150
High							1,023	1,123	1,186	1,258	1,333	1,415	1,419	1,416	1,428	1,436	1,442

Source: Australian Energy Market Operator.

7 The Western Australian natural gas market has the following features: a limited number of large suppliers and consumers; bilateral, commercial and long-term take-or-pay gas sales contracts; residential, commercial, and small industrial consumers comprising around 15 percent of total demand; small volumes of short-term and spot gas sales; a small number of pipelines and interconnectors, with limited surplus pipeline capacity; limited information about supply that is available to be contracted, potential buyers, and gas contract pricing; and storage capacity of 78 PJ, that can receive gas at up to 160 TJ/day and supply gas at up to 210 TJ/day.

In this same report, there was a breakdown of forecast usage by sector:[8]

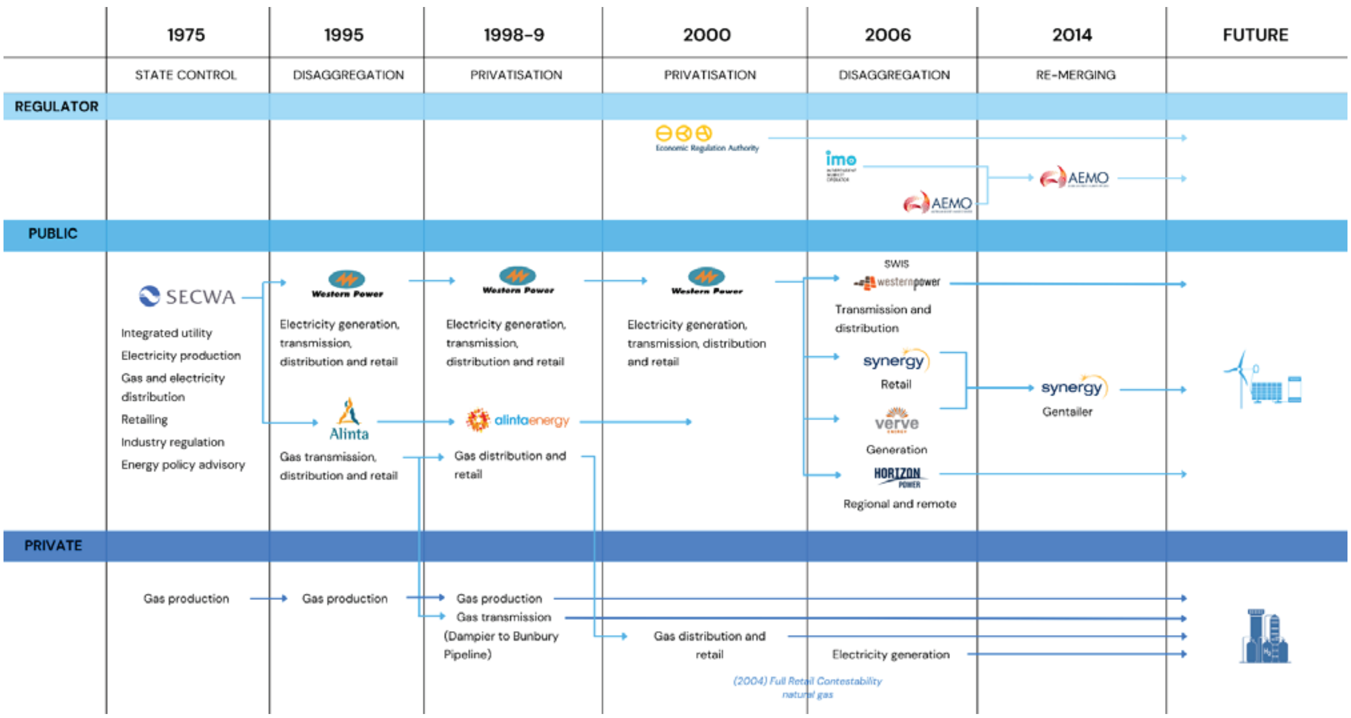
Figure 4: Domestic Gas Demand Forecasts by Usage Category. Base Scenario, 2022 to 2031



Sector	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Mineral processing	317	331	332	338	338	338	337	338	338	338
Mining	316	346	353	356	355	353	356	360	366	369
Industry	189	198	192	192	191	191	182	183	183	183
GPG	172	171	167	164	169	168	172	171	169	178
Distribution	78	79	79	79	80	80	80	81	82	83

Source: Australian Energy Market Operator.

2.4 Structure of energy sector



8 GPG refers to domestic power generation and industry includes major users such as ammonia, fertiliser, and liquefied petroleum gas production.

2.5 Decision-making in energy sector

As highlighted in the overview of the structure of the system, gas assets are largely private and electricity assets are predominantly public. The below table highlights the key decision-making roles, bodies and authorities.

	Gas	Electricity
Retail pricing	Full retail contestability since 2004	"Small use customer" (consumes no more than 160MWh of electricity per annum)- price set by government "Contestable customer" (Consume 50MWh or more of electricity per annum)- price set by bilateral negotiation
Regulation	The Economic Regulatory Authority regulates the transmission and distribution network cost component of some gas and electricity transmission and distribution networks.	
Network tariff	Approve access arrangements for three full regulated pipelines in Western Australia: the Dampier to Bunbury Natural Gas Pipeline, Goldfields Gas Pipeline, and Mid-West and South-West Gas Distribution System.	Approve access arrangements for Western Power's electricity transmission and distribution networks. (Completed on a five-year cycle).
Energy Policy	Energy Policy WA: "advises the Minister for Energy on energy policy, to assist the Western Australian Government in making well-informed decisions that contribute to the delivery of secure, reliable, sustainable and affordable energy services to Western Australian households and businesses." Established September 5, 2019, as a standalone sub-department of the Department of Mines, Industry Regulation and Safety.	

2.6 Gas market decision-making

Aside from the network access arrangements, there is a predominance of market forces. Earlier reforms and privatisation of the sector has meant that there is limited government involvement. The Western Australian retail gas market became fully contestable in 2004 and there are several retailers. There is one Retail Market Scheme that covers all of ATCO Gas Australia's distribution systems. The Australian Energy Market Operator is the scheme administrator. The Economic Regulation Authority has regulatory oversight of this scheme as well as any future Western Australian schemes.

2.7 Electricity market decision-making

Given that electricity retail prices are set by government, and the utilities are also owned by government, the energy minister exercises significant influence over the sector. While the economic regulator approves the access arrangement for transmission and distribution networks, the liabilities (relating to the difference between retail prices and costs of production) and responsibility for keeping the lights on ultimately sit with government.

3 Reform trajectory over the past decade

The past decade in the Western Australian energy sector has been noted for two key trends: the shift away from privatisation and deregulation, as well as a coordinated effort to address the implications of decarbonisation. Each requires explanation.

Despite a comprehensive privatisation and deregulation roadmap presented to a centre-left Premier in 1992, the political class and energy sector never fully embraced reforms. As the momentum slowed during the 2010s, and ultimately reversed, the electricity sector was neither private nor public which was described by many as 'half-pregnant'. The last major structural reform was to re-merge the government owned retailer and generation entity in 2014.

A former senior minister, when reflecting on the lack of controversy on the shift to full retail contestability for natural gas in the early 2000s, noted that this reform was bi-partisan and was in an era when privatisation and deregulation were commonly accepted. This centre-left Treasurer also established the economic regulator which would oversee the sector and report to parliament rather than the Treasurer or Energy minister. Thus, while the government retained the ability to set retail electricity prices, it established a regulatory process and a wholesale energy market.[9]

When pushed on contemporary developments, the above-mentioned Treasurer noted that reform was now more challenging and there was a limited internal capacity to address the complicated challenges of the contemporary era.[10] In interviews it was repeated by different individuals that incremental reform was now the optimal approach. Evolution rather than revolution is the only politically available option. Equity issues were raised, but these related to traditional concerns regarding the impact of energy costs on poorer households. At present, there have not been any substantive calls for a 'just transition' which radically redefines subsidisation with the energy system as a welfare mechanism. Pragmatism remains, with a blackout resulting in air conditioners not working on a 40-degree day being the largest concern. Notably, a partial blackout occurred on Boxing Day 2021 with a subsequent announcement of an inquiry. Of the various informal discussions with a range of energy ministers that have held office over the past 20 years, this is the one reoccurring theme in all interactions. The overriding desire above ideology and climate change was 'keeping the lights on'.

Decarbonisation has not been formally stated as a priority of any state government, be it centre-left or centre-right, although various environmental initiatives and efficiency initiatives have been implemented. Rather, the momentum of a coal and natural gas-based industry has meant that decision makers have been focused on the accommodation of large-scale wind farms and residential solar. The growth in renewables was largely driven by federal incentives, although a state-based solar feed in tariff proved extremely popular and accelerated the deployment of residential solar.

Throughout the 2010s, the impact of increasing renewable generation was starting to have a material impact on the grid. This renewable growth in an islanded grid, with pressure to phase out aging coal generation, was causing physical and economic stress. Integrating ever-increasing renewables proved technically challenging and upended long-running practices. On the economic front, the erosion of revenue from solar and wind (which spilled onto the system), and a retail price structure which underweighted a fixed charge for electricity users as well as hesitancy to raise retail prices saw the deficit accelerate. Indirect government subsidisation occurred through growth of debt on the balance sheet of the Crown gen-tailer.

9 An outsider may view the arrangements of regulator establishing the cost base and the government retaining the ability to set retail prices as an incomplete reform. This was one of the outcomes of the 2006 political compromise in which the then opposition leader created a wedge over the impact that the changes would have on households. Not only was the ability to set retail prices retained by the government, but retail tariffs were frozen for some time. In real terms the price declined. This created significant challenges to the Crown balance sheets and distortions within the entire energy sector. The experience highlights than any reform process will be subject to a scare campaign and policy outcomes which reflect the politics of the day rather than an optimal outcome.

10 Policy expertise was hollowed out for a range of reasons. The dispersal of functions reduced critical mass. Also, with less influence, it did not attract the best and brightest. While policy capacity continued on a head count basis, it atrophied.

During the 2010s, a reformist energy minister used the remote and regional entity, Horizon Power, to test new pricing and retail arrangements. This pilot operated outside the metropolitan centre of Perth and was less prone to backlash or protests. It was aided by a small and nimble (as well as integrated) Crown utility which was operationally flexible and could implement changes relatively quickly. The same minister pushed efficiencies through prudent management of the gen-tailer Synergy which reduced the de-facto taxpayer subsidy. During the 2010s, the framework of who pays and how can be summarised by the below table.

Category	Expectation of funding energy transition
Existing Ratepayers	Minimal tolerance for any burden associated with cost of energy provision outside of generation and fuel, let alone energy transition. Strong desire to continue to have an electricity service provided with a cost structure of a commodity. Extreme resistance to a reweighting towards a greater fixed cost to match economic profile of sector.
Future Ratepayers (Crown utility debt)	Traditional approach to energy transition costs are to use Crowns and their balance sheets to absorb impact. Prior to 2010, this was not material but was increasing. Over the past decade efficiency drives and minimal changes to retail cost structure have slowed down the impact. Trend for accelerating accumulation of debt through fast growing integration costs.
Taxpayers (Immediate transfer from government)	Increasing realisation that transition costs will not be able to be absorbed by Crown balance sheets. With regulator not agreeing to smart meters in rate case, the government funded the deployment directly. The current model for government to directly fund these larger, non-business as usual assets appears to be established. (It is important to note that due to royalty revenues, the Western Australian government has a relatively strong fiscal position allowing it flexibility to fund large ticket items.)

Through a cabinet reshuffle in 2014, the energy minister assumed responsibility for Treasury (equivalent of finance minister). This arrangement continued through a change of government until 2018. Both ministers have noted that overseeing the energy portfolio while seeing the expanding costs to the state helped clarify the challenge. They also lamented the lack of an internal expertise within their departments and the extent to which the government owned utilities were running their own agenda. This analyst spent time as an energy advisor in a peak industry group where a set of proposed changes were put forward. This included referring regulatory processes to the federal Australian Energy Regulator[11] as well as a range of technical reforms to optimise the grid for renewables. It also involved a shift from a constrained to unconstrained network and other uncontroversial changes, although there was some debate on moving to the federal regulator. Due to the nature of these reforms, including the need for the upper house committee to review the federal aspects, these changes had to go through a longer legislative process. They were left too late in the parliamentary schedule to pass. The bill was ultimately derailed through the calling of an election. (**Finding 1**)

A key realisation by all participants was that outside a supply crisis, there needed to be a more substantive and centralised policy expertise within government to manage the challenges associated with decarbonisation. The limited and hollowed out energy expertise was addressed by the creation of "Energy Policy WA" on 5 September 2019. The subsequent section on key legislative and regulatory reforms is predominantly focused on the post-2019 reforms which were driven by Energy Policy WA. This entity appears to have taken on many of the policy functions which existed within the previously integrated Crown utility. (**Finding 2**)

11 At least one person interviewed indicated that by moving the regulatory authority into the national realm, there could be more political distance between the likely unpopular decisions. It was also seen as a way in which pressure could be put on Crown utilities as the federal regulator would have less direct personal connections with those in the Western Australian energy sector.

4 Key legislative and regulatory reforms

4.1 Energy Transformation Strategy 2019-2021

The main focus of this case study will be the decarbonisation initiatives relating to the electricity sector which occurred between 2019-2021. Two important vehicles were used by the government: a time limited Energy Transformation Taskforce and a 'Micro-grid' inquiry run by the Standing Committee of the Legislative Assembly. These mechanisms were important for the following reasons:

- Both were not formally connected to the energy minister, but both provided visibility on the processes and permitted indirect oversight (by the minister's office).
- Input from industry could occur through the Standing Committee, with long running tensions between private interests and Crown entities aired in a neutral forum.
- The taskforce had an end point, so it was focused on outcomes rather than establishing itself as another entity in a crowded and contested space.
- While nominally focused on 'micro-grids' the Standing Committee could socialise some of the market reforms necessary for decarbonisation and changes to regulatory/legislative settings.

While colloquially known as the 'Micro-grid' inquiry, its full title provides an indication of the broader purpose *Taking Charge: Western Australia's Transition to a Distributed Energy Future*. The issues raised in the inquiry were largely understood by industry participants and the findings and recommendations generally meshed with government priorities. One of the unstated purposes of the exercise was to address structural reform required by decarbonisation trends to:

- Clarify the respective role of Crown utilities;
- Flag the demarcation of the grey areas of batteries;
- Highlight that regulator followed a narrow, traditional approach to access arrangements (equivalent of rate cases);
- Promote tariff reform at the network level as well as hint at shifts in retail pricing and mechanisms; and
- Act as an informal mechanism to educate future ministers and senior bureaucratic leaders. (**Finding 3**)

While the idea of a micro-grid is not new, it is used as a concept for public communication as it resonates with expectations of an energy system which involves PV, batteries and EVs. Any discussion or framing of grid level challenges and operational difficulties is well beyond the bandwidth of electors and the politicians that represent them. Thus, with PVs and microgrids, there are two different conversations. One at the household level over concern with their utility bill, and the other at the system level.

The framing of micro-grids and community related services is one way in which some of the trade-offs and challenges associated with decarbonisation can be translated to the community and household level. This comes after a belated realisation that technical descriptions by electrical engineers do not spark the imagination of consumers (and voters). 'PowerBanks', essentially community level batteries, offers a tangible link (at a suburb level) and provides more options to the system operator. This continues with the roll-out of PowerBank batteries across 13 locations in the SWIS principally to address thermal overload.

In another Australian jurisdiction, a former Energy and Climate minister who represented the progressive wing of a centre-left party lamented the practical challenges associated with decarbonisation and the demands by green groups. This minister also found that community or suburb level initiatives provided a useful mechanism for conveying trade-offs associated with energy policy. Instead of presenting the optimal solution for decarbonisation, the challenges were offered at a relatable level. While this may have not been the most efficient system-wide approach, it helped shift energy discussions to the middle ground.

In Western Australia, one of the consequences of the reform process was the fragmentation of energy expertise and technical understanding in government. In the early 2010s, the author of this case study spent time in Western Power, the Crown transmission and distribution entity, to specifically build up capacity on national policy. Other Crown utilities developed similar capacities and policy depth, aided by technical and operational specialists. The agency responsible for energy policy tended to be a second-tier player and more compliance-focused rather than able to navigate the substantive changes facing the industry. There were repeated references to the fact that this entity was unable to quantify the number of solar panels or capacity added to the system. While likely an exaggeration, a few respondents referred to this entity considering the use of satellite imagery to ascertain the level of PV deployment. Dysfunction and ineptness were frequent descriptions of this policy function.

In 2018, the incoming government was faced with extremely limited internal energy policy skills or expertise. Faced with a pending release by the AEMO (market operator) about the significant challenges associated with system management on March 6, 2019, the Minister for Energy announced the Government's 'Energy Transformation Strategy'. The AEMO report, *Integrating Utility-scale Renewables and Distributed Energy Resources in the South West Interconnected System* outlined the challenges associated with integrating utility-scale and small-scale renewables. It pointed to issues which would arise in the short- to medium-term which could not be deferred.[12] Political action had to occur, and it sped up existing activities as the timing was within the term of the sitting government.

The Energy Transformation strategy was the first systemic approach to deal with the practical challenges associated with decarbonisation. It had very little ideological characteristics and was driven through the realisation that a business-as-usual approach would result in a failure of the system, market as well as the overall viability of the sector. The strategy was not unique and similar actions occurred in other jurisdictions. It was reactive in that it was established to manage challenges and respond to the energy transformation underway and to plan for the future of the power system.

Western Australian has never sought or claimed to be at the leading edge of decarbonisation policy and initiatives. Nonetheless, the practical approach to the strategy is informative to Canadian decision makers. Many provinces have similar powerful incumbent Crowns and a dearth of talent in policy roles supporting the relevant ministers and their advisors. This point should be stressed. Throughout the author's informal discussions with a range of public and private industry players it became clear there was 'limited bench' of bureaucratic expertise on the practicalities of decarbonisation. It was noted that there were often requirements to provide multiple briefings on technical issues and context before policy suggestions could be proposed. Most respondents indicated that this was frustrating and meant anything non-urgent tended to grind to a halt.

This inertia was recognised in the Micro-grid inquiry which noted: 'Since the establishment of the Wholesale Electricity market in the mid-2000s, no government has undertaken a significant reform process to restructure markets or adapt regulatory frameworks.' (Shaw 2020, p. 69). Re-establishing a capacity within government to assist with the decarbonisation process would not occur in one step and needed a patient approach.

Instead of establishing a large permanent energy bureaucracy, one innovation was to establish a taskforce to deliver the Energy Transformation Strategy. This was chaired by an independent economist specialising in the reform and regulation of utility services, but also included representatives from the Department of Treasury, Department of the Premier and Cabinet, Energy Policy WA and the Office of the Minister for Energy (ministerial advisor).[13] The independent chair had previously been the chair of the Australian Energy Regulator as well as on the board of the Western Australia economic regulator.

12 AMEO produced an update to this report in September 2021 titled: *Renewable Energy Integration – SWIS Update*. See: https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf?la=en

13 Climate change and emissions now nominally sit under the Minister for Environment and Climate Action. However, this remains a relatively junior portfolio when compared with most Canadian jurisdictions. Generally, the de facto decision maker on environment policy is the premier and the economic development minister. A like for like comparison with Canadian ministerial counterparts is not always appropriate. For example, in most Australian jurisdictions, the arts and culture portfolio are one of the least important ministerial roles, whereas in Canada the role is generally more prestigious and carries more weight at the cabinet table.

Insiders noted that the taskforce was established to respond to the problematic AEMO report. This was not a grand design, rather the reactive response characteristic of modern politics. Regardless of origins, the taskforce ended up being a very useful tool to push reform. Many respondents commented on the advantages of this model. Firstly, it was not permanent, and the chair did not have an ongoing interest in future activities. Secondly, it had a small number of key decision makers. Thirdly, Treasury involvement was key as the cost of any changes was considered. Finally, while the minister was represented, the relatively junior advisor acted as a conduit rather than a driver of a preferred outcome. (**Finding 4**)

The taskforce completed three work streams:

- Distributed Energy Resources
- Whole of System Planning
- Foundation Regulatory Frameworks (Improving Access to the SWIS and Delivering the Future Power System)

While each work stream could be a case study on its own, only the key observations relevant to this analysis will be included.

4.2 Distributed Energy Resources

As the SWIS is an islanded and relatively small grid, the rapid uptake of PV has proven challenging, for both the duck curve phenomenon as well as the minimum load issues. At the distribution levels, in addition to PV, there are a range of smaller-scale devices that can either use, generate or store electricity which are likely to impact the grid. Policy makers realised that there will not be a single solution or permanent fix, but rather continuous adaptations as these devices proliferate.

In April 2020, the taskforce produced a DER Roadmap and 36 actions which are to be implemented by 2024. This included the deployment of community batteries, reactive power, a register of DER and pilot tariff schemes. Many of these initiatives have been implemented across the world. Previously these types of initiatives were driven by the utilities based on expected changes and their preferred approach. The effective re-centralisation of energy policy making and oversight, as well as a continuous process of reform, has altered the role of utilities and expanded the tools available to the energy minister. (**Finding 5**)

4.3 Whole of System Planning

Prior to unbundling and in the period of vertical integration, large Crown utilities completed Integrated System Plans. The trade offs, transmission planning and major generation investments were internally decided, often with informal oversight by the government in the form of Treasury feedback on debt levels. Market reforms ended this practice. However, in a return to the past, the taskforce completed a so-called 'inaugural Whole of System Plan'. It produced four scenarios and the exercise will be repeated in September 2025. Participants noted that this was not a serious exercise; the approach was conducted like a management consultant facilitating a strategic planning session and four scenarios are meaningless for any internal planning or orientation. A key shortcoming was that a carbon price was not formally included. Separating energy and carbon markets was a shortcoming of this forward-looking exercise. (**Finding 6**)

4.4 Foundation Regulatory Frameworks

This aspect of the taskforce work covers a wide range of regulatory, technical and market changes. Most of these related to optimising the system while it transitions. Others, such as the move to constrained network access was slated as a long-planned change but was frequently dropped due to other priorities (see discussion above on election timing). Many of these reforms provide the basis for greater amounts of renewable energy. While not publicly stated, they also help to provide a level playing field so that the Crown utilities do not end up subsidising private operators while their plant degrades at a faster rate due to rapid ramp up and ramp down.

One of the important reforms was undertaking revisions to the provision of Essential System Services (ESS), also referred to as ancillary services. The legacy Crown gen-tailer and another private operator were providing these services without compensation. In a traditional large, conventional dispatch model this would not have an impact. However, with renewable generation spilling onto the system, there needed to be a formalisation of this process which recognises the value to the system. The reform allows generators and large energy storage facilities to assist in maintaining the power system within its prescribed voltage and frequency limits.

A key learning from this aspect of the reform process was the way a private generation company was able to frame the impact of providing an ESS without compensation whereas in the east coast national energy market, it is regarded as a service for remuneration (Shaw 2020, p. 99). As technology permits a shift to real time markets, private industry should be ready to identify more instances where they are (or could be) providing a service at a time and location which helps address the challenges of the transition. (**Finding 7**)

From the perspective of a Crown entity, it was noted that appointing a 'chief economist' enabled the organisation to frame the issues of ESS and other challenges on what appeared to be a more independent basis. Simply having the capacity to produce an economic model of a proposed change or trend ensured that any 'thought bubbles' from the elected officials had a quick reality check. While the economist was on staff, the delivery of the message was more acceptable to the government. It also gave the utility visibility on considerations of the minister's office. This included modelling electricity tariffs using the existing framework for water (a different fixed versus variable charge). Private industry economists were invited to participate in policy discussions. This author was involved in a series of small briefings and roundtables nominally under the guise of economic roundtables. When senior decision makers (ministers and chiefs of staff) were involved in these discussions, there was a tendency to rely on input from external 'experts' as they were viewed as 'not having a dog in the fight'. (**Finding 8**)

4.5 Governance

Most of those interviewed for this report noted that the prior governance arrangements established in the 1990s and early 2000s were obsolete, inflexible and unclear in their delineation of responsibilities. Being 'half pregnant' with partial privatisation, alongside politically decided retail tariffs, meant that there was no scale or coordination benefits of a fully public system, nor the benefits from market-based competition. A common response was 'no one is in charge'. The lack of a single focal point or governance body tasked with setting overall direction for the energy sector was repeatedly noted.

As part of the reform process, several changes were made which addressed this shortcoming:

- Energy Policy WA was created, and a time limited taskforce (discussed above) was established.
- The government transferred the functions of the former Rule Change Panel, and the Economic Regulation Authority's responsibility for a number of policy and technical reviews under the Wholesale Electricity Market Rules to Energy Policy WA.
- Energy Policy WA was tasked with broader market development functions for the Wholesale Electricity Market and Gas Service Information arrangements, the ongoing development of Whole of System Plans for the South West Interconnected System, and market development and rule administration.

This recentralisation of the technical and policy aspects of the energy sector was not implemented to 'punish' the regulator. Indeed, it had performed its function as per the relevant act and provided a robust process to review proposed access arrangements (a large component of electricity costs). Furthermore, when the economic regulator did not approve the network operator's proposal for recovering the costs of smart meters, the government funded their deployment directly. (Shaw 2020, p. 55). Continuing with an independent economic regulator which followed the least costly, prudent approach is a given. However, transformation would be coordinated by Energy Policy WA with any necessary changes funded and managed directly by government and Crown utilities. (**Finding 9**)

As always, there was a negative sentiment directed at the shortcomings of the regulator in that it took a narrow approach. This was largely voiced by the government and impacted utilities. However, critics still favoured an independent regulator as a separate entity which could be criticised. This was a political perspective and not about optimising the regulatory system and associated legislative framework. Household utility bills are measured by the daily news cycle and reform of regulatory frameworks are measured in years. In general, the Australia political system is less consensus and process focused than Canada. Australians are generally less deferential to independent and statutory bodies. There were some decision makers that were less tolerant of a regulator which was not 'evolving with the times' in following a strict economic definition for rate cases. While none went as far as calling to abolish the regulator, there was discussion of neutralising it while still operating within the legislative framework. (**Finding 10**)

4.6 Consumer representation and feedback

Historically, the mechanism for consumer feedback in the electricity sector to electricity providers has been limited. Aside from complaints processes administered by Crown entities, the lack of feedback mechanisms has proved challenging. Furthermore, talk frequently does not match actions. In the early 2000s, a pilot green energy scheme was closed due to lack of interest. Informally, an executive at the Crown gen-tailor acknowledged the 'tsunami' of calls that they were receiving seeking 100 percent green energy and wanting it to be cheaper as 'sunshine is free'. Participants in the sector noted that voters would make demands on politicians, and politicians would respond accordingly.

There was a general agreement between the utilities, policy makers and politicians that fighting the love affair with PVs (and expanding EVs) is a losing battle. Rather, efforts were focused on incremental reforms to have an indirect time of use price or incentive to time shift. This author was reminded of the sentiment towards negative prices and other mechanisms which would be economically efficient but would be 'political suicide'. Efforts were focused on consumer education and greater practical responsiveness to DER as well as new consumer products. This appears to be a real effort and from most respondents, the Crown gen-tailer has got much better at this over the past decade. The challenge is that consumer expectations have risen at a faster rate. At a government level, Energy Policy WA have taken the lead in engaging with consumers and consumer interest groups. This was seen to be more effective than the utilities. The Crown utility executives noted that as there were still negative attitudes it was a large integrated entity dominated by engineers that was unresponsive to consumer requests. It was also pointed out that the organisation which sends the utility bill out each month is always starting on the back foot. (**Finding 11**)

4.7 Stand Alone Power Systems

Like Canada, many parts of Western Australia are remote and extremely isolated. The network operator frequently refers to the fact that 52 percent of the network services less than 3 percent of the users. In many cases, a stand-alone power system (SAPS) would offer a cost competitive solution but there is a great deal of resistance for changing the current arrangements. A major fire in the Esperance region (at the fringe of the grid) in 2016 provided the impetus to trial an integrated solar, diesel and battery offering. Anecdotally, negative sentiment and a preference to be reconnected to the grid were replaced by envy of those who subsequently wanted their own SAPS. Significant community engagement and liaison was necessary for the SAPS to be initially accepted. (**Finding 12**)

Most of the barriers to the deployment to SAPS were addressed in 2020. However, there remain several regulatory amendments required in relation to customer engagement, obligation of network service providers, and reliability and quality reporting. This indicates unnecessary delay and coordination, but it was suggested that this time allowed for appropriate standards to be developed as well as appropriate tendering mechanisms for private companies to participate. (**Finding 13**)

4.8 Coal mining regions

The elephant in the room in all Western Australian energy discussions was the end date of coal mining and electricity production in the Collie region. This mining centre, over a hundred years old, is akin to counterparts across North America and similar worker and transition issues abound. While the end of coal was first mentioned by an energy minister in 2016, much has been done to manage this transition towards a non-fossil fuel future. One participant described the last few years as a tripartite effort between unions, the Crown utilities and the energy minister. It is viewed to be successful (to date) because: the minister becomes involved and will physically go to the region to discuss matters directly with workers; the Crown has located a full-time community liaison representative in the region; and expectations are closely managed to avoid a perception of comparable roles immediately available within the region. It included tailored worker transition support and diversification. There are no promises but what one close participant described as a 'long slog'. (**Finding 14**)

4.9 WA renewable hydrogen strategy

The gas sector has been largely privatised and is subject to market forces. This is partly due to the lengthy period of cheap natural gas, which was attributed to a large, long-term take or pay supply contract signed by the integrated Crown utility in the 1980s to help underwrite the then-emerging LNG sector. Memories of this 'bold' initiative to create a new energy sector still linger. Both government and opposition still view the utilities, especially Crown utilities, as a tool to facilitate energy export sectors. The main issue facing the natural gas sector has been the ambitions to export green hydrogen and the impact that this will have on domestic systems.[14] Industry has had to respond to bi-partisan ambitions for Western Australia to become a green hydrogen 'superpower'. This has been fuelled by substantial hype around the potential for green hydrogen and limited understanding by the political class and business community of the transition costs and challenges.

Unlike electricity, which sits under Energy Policy WA, natural gas is viewed primarily as an export commodity and the preeminent policy agency is the Department of Jobs, Tourism, Science and Innovation (JTSI). JTSI is an economic development and international trade agency. Hydrogen is therefore a matter for JTSI which complicates the domestic entities. A key issue for natural gas utilities was the lack of technical expertise relating to hydrogen in JTSI and the expectation gap between physical systems (and associated economics) with ambitions.

As a pre-emptive move, a natural gas network company is planning to run hydrogen trials in two different locations. The volumes and commercial returns are insignificant, and they are best described as demonstration plants. Some observers describe it as a 'PR exercise'. However, these efforts have helped reposition the organisation and overall sector. One of the larger concerns is when blending exceeds 10 percent hydrogen. Informal lobbying has resulted in the government funding studies to examine the technical aspects of converting pipelines to hydrogen. While this is focused on domestic use and the incremental introduction of hydrogen to the conventional gas system, the larger prize is being able to facilitate exports given there is only a relatively small domestic market.(**Finding 15**)

Insights beyond Western Australia

As COVID-19 spread across the community in early stages of the pandemic, there was a realisation that any economic recovery would need to address the increase in energy prices to attract manufacturing and mineral processing investments. Industry had become frustrated with the lack of understanding of international cost competitiveness and both major parties understood voter aspirations for well paying manufacturing jobs. The 'COVID-19 Co-ordination Commission' was an expert panel appointed by the Prime Minister's office to consider the recovery and what changes would need to be implemented. With a panel that included Andrew Liveris, the former chairman and chief executive of the Dow Chemical Company recommendations included public ownership of new gas pipelines, underwritten gas supply projects and a national gas reservation policy. It also flagged 'guaranteed off-take' agreements to facilitate new pipelines.

The public commentary of the role of natural gas in the economic recovery was not met with universal acceptance, although by positioning it towards the growth of blue-collar jobs and the regions made it politically challenging to reject outright. While the Commission ultimately wrapped up its work and the bold plans were not implemented, it had the impact of shifting discussion of natural gas, and associated infrastructure, towards the economy, recovery and blue-collar jobs. This reframing has resulted in a different public view on pipelines as a facilitator of economic growth. Discussions of being carriers of green hydrogen further neutralise some of the negative commentary. (**Finding 16**)

14 Most plans include a blue hydrogen phase with green hydrogen being the ultimate target.

5 Lessons learned

General Finding: The overriding desire of elected officials, their advisors and senior bureaucrats, well above ideology and climate change concerns, is 'keeping the lights on' and avoiding household pain with electricity bills. No reform will progress if it fails these tests. This is a litmus test when proposing changes.

General Finding: Environmental and sustainability will factor more in future energy decisions. However, energy reform and policy making was traditionally dominated by economically oriented and technically competent organisations. Should there be an official 2030 target, the Environmental and Climate Action Minister will become a more important decision maker. This will likely create further internal tensions within government as well as the broader society as major new LNG projects are proposed.

Finding 1: Proceed with legislative changes incrementally. A big bang approach can get lost, especially if it relates to non-controversial regulatory settings.

Finding 2: The reform process from the 1990s to around 2014 hollowed out the internal energy policy capacity within governments which proved to be inadequate for the challenges posed by decarbonisation. Even with limited privatisation, the trend towards decentralisation resulted in silos of competing actors in Crown utilities, regulators and market operators. Even amongst private operators there was agreement on the need for centralised, bureaucratic technical expertise that is separate from the ministerial advisory function.

Finding 3: An ad-hoc parliamentary inquiry provides a mechanism to promote reform and gauge industry feedback without formally committing the government to action. It also serves as an important mechanism for future ministers to understand complex regulatory, economic and energy related issues (most who sit on this committee end up as the energy minister and/or treasurer). This is important when very few elected politicians, especially in the lower house, understand the energy system or regulatory frameworks.

Finding 4: In the instance when internal policy making skills do not exist within provincial governments, a time-limited high-level taskforce, tasked with specific actions, can help rebuild capacity without creating an unwieldy bureaucracy. This model is very useful if industry feedback and interaction is needed but would be problematic if directly with the energy minister's office.

Finding 5: A senior utility executive stressed the importance of a layered consultation process when the contentious distributed energy resources policy needed to be clarified. This could include a public forum, invite-only broad gathering and a limited group to create an actionable list.

Finding 6: If a whole of system planning exercise is conducted, there needs to be clarity on the outcome and a true alignment of agreed outcomes rather than a symbolic activity.

Finding 7: It is easier for private operators to shape energy policy if they are involved in energy policy proposals at their inception and can frame the reform in terms of supporting the transition rather than revenue growth.

Finding 8: Appointing a chief economist within a utility (public or private) offers ability to have informal discussions with counterparts, pre-emptively (and politely) address thought bubbles, maintain visibility of policy proposals as well as convene external experts to carry a message to decision makers.

Finding 9: The transformation of the energy sector will require changes to governance and regulation. One option is to narrow and continue the traditional role of the economic regulator but create a larger, internal energy policy and coordination function with new initiatives directly funded by government rather than spread across consumers. This is the least economically efficient approach as it blunts the impact of price mechanism to change behaviour and stimulate investment. In a partially privatised system, it returns government to de facto allocator of capital and dominant player.

Finding 10: Pressure on regulators is likely to increase as governments expect a wider interpretation of existing legislation. The optimal solution would be for the government to lead a bi-partisan effort to reform the function, role and duties of the regulator to respond to the fast-changing energy sector. There is no indication that this will occur. Market participants should be prepared for changes which keep the regulator and existing framework intact but alter its direction and priorities.

Finding 11: A consumer feedback/education function separate to the utilities has a greater chance of success. Education programs which deal with unrealistic expectations of consumers are important, although facilitating change and new consumer products is now the minimum expectation of Crown utilities.

Finding 12: A technically superior, non-network solution is very difficult to implement under a business-as-usual scenario. Pilot schemes are useful. However, the greatest potential comes when there is a significant event or change of circumstance. Success when deploying non-network solutions relies on ensuring any interim offering or emergency deployment exceeds service expectations.

Finding 13: Introducing a reform package to facilitate Stand Alone Power Systems and ultimately micro-grids will attract equipment suppliers and other interests pushing for immediate change. In these instances, managing expectations of timelines is important.

Finding 14: When dealing with a community in transition away from fossil-fuels, there is a need for frank and direct conversations with a long-term plan which avoids gimmicky offerings and expectations of a quick fix.

Finding 15: For natural gas transmission organisations, government backed, external engineering studies are helpful to have an independent expert provide analysis on the practicalities and issues associated with blending hydrogen and full conversion.

Finding 16: By reframing natural gas as part of the economic recovery from COVID-19, with the inclusion of suitable qualified senior executives with an international reputation, it was possible for natural gas pipelines to be viewed as a facilitator of growth. Pivoting towards being a green hydrogen carrier further helped shift the narrative.

Postscript

This report was completed in early 2022. As of June 2023, there have been a number of signification political developments which have accelerated the decarbonisation trend. A key shift in the direction of climate change policy was the May 2022 federal election. This saw a change in the government, with the centre-left Australian Labor Party (ALP) returning to power after nine years in opposition. Elected on a platform to implement climate change policies, there have been two key acts that have passed parliament which provide the national framework for decarbonisation:

- *Climate Change Act 2022*: An Act to set out Australia's greenhouse gas emissions reduction targets, to provide for annual climate change statements, to confer advisory functions on the Climate Change Authority, and for related purposes.
- *Safeguard Mechanism (Crediting) Amendment Act 2023*: Act to amend legislation relating to emissions reductions, and for related purposes.

The *Climate Change Act* (2022) set a 43 percent reduction of emissions below 2005 levels by 2030. The safeguard legislation provided a mechanism for the reduction of emissions from large industrial facilities (over 100,000 tonnes of emissions per year) with a 'hard cap on pollution' negotiated into the bill by a minor party on the Senate. The impact of this mechanism is still being considered. However, it points to an acceleration of the offshoring of trade-exposed, emissions intensive industry (de-industrialisation). The new ALP government also introduce price-gaps for natural gas in the east coast market and the Queensland government introduced a new tax on coal exports.

The cumulative impact of these government interventions and taxes has slowed investment. It also earned a public rebuke from the Japanese government, which is reliant on Australia resource exports. In Western Australia, which is on a separate grid and operates a different gas export framework, the government has worked on a business-as-usual approach to energy and climate policy. The June 2022 announcement on retiring the state-owned coal fleet was largely expected, with the outcome being the culmination of several years of consultation and forward planning. This public announcement could not have been delayed any longer.

Given the change in federal government and new emissions target and safeguard mechanism, the Western Australian government has cautiously committed itself to emissions reduction legislation at the end of 2023. Should this extend beyond state-owned assets, it may cause significant political challenges given the large LNG investment decisions slated for the short term. However, with the new safeguard mechanism and hard cap, they will already be be facing further headwinds. One interesting area to watch will be the extent to which the Western Australian Environmental Protection Agency will continue to require emissions targets and state-based reporting on top of a newly expanded federal remit. This is akin to the Canadian provinces moving ahead of the Harper government on environmental policies which created a patchwork of climate policies and decarbonisation mechanisms.

Finally, the rush to hydrogen export projects was not as rapid as expected and many of the significant proposals remain in concept stage. There is a greater realisation that this sector will not replace the LNG sector and private investors will still need an appropriate rate of return. This applies to the broader electricity sector where there is still a large degree of uncertainty and increasing reference to sovereign risk. As such, much of the energy transition will likely be funded by governments and ultimately taxpayers.

Exclusions and qualifications

This report has aimed to convey an insider's perspective on energy reform with practical insights relevant for industry, policymakers and regulators. While a great deal translates directly, it has been noted by some leaders with experience in both countries that Australians will tolerate more friction and debate as opposed to Canadians who prefer consensus and adherence to established processes.

In a review of technical matters, engineers with international experience noted that electrons and natural gas molecules are predictable, but the variance between English-speaking Commonwealth nations is more substantial than initially expected. However, it was noted that an Australian approach to reform or policy always was seen more favourably than a US example when presented to a Canadian policy maker. This is the same with health policy and reform.

Municipal government has not been discussed in this case study as municipalities are largely peripheral to energy policy except for symbolic resolutions. Their role and tax base are much more limited than Canadian counterparts. While there was consideration of including municipal governments it was decided not to include due to lack of relevance in the Australian context.

Like Canadians, Australians are less enamoured with price signals and any variance between urban and rural services. The matter of who pays is not a simple answer. In general, it is now the taxpayer that funds changes either directly or indirectly.

Methodology

This case study has drawn on the author's experience over two decades in and around the Western Australian energy sector. It has benefited from extensive interaction and work with several energy ministers across the political spectrum as well as their advisors and cabinet counterparts (especially in the treasury/finance function). All the energy ministers that have held office over the past two decades were interviewed for this Case Study. There were 13 informal interviews with a range of utility executives (electricity and gas as well as public and private); regulators; external consultants; energy economists and electrical engineers. Almost all discussions about developments in Canada indicated that transitioning electricity and natural gas systems is a universal issue which policy makers, industry and regulators are grappling with.

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