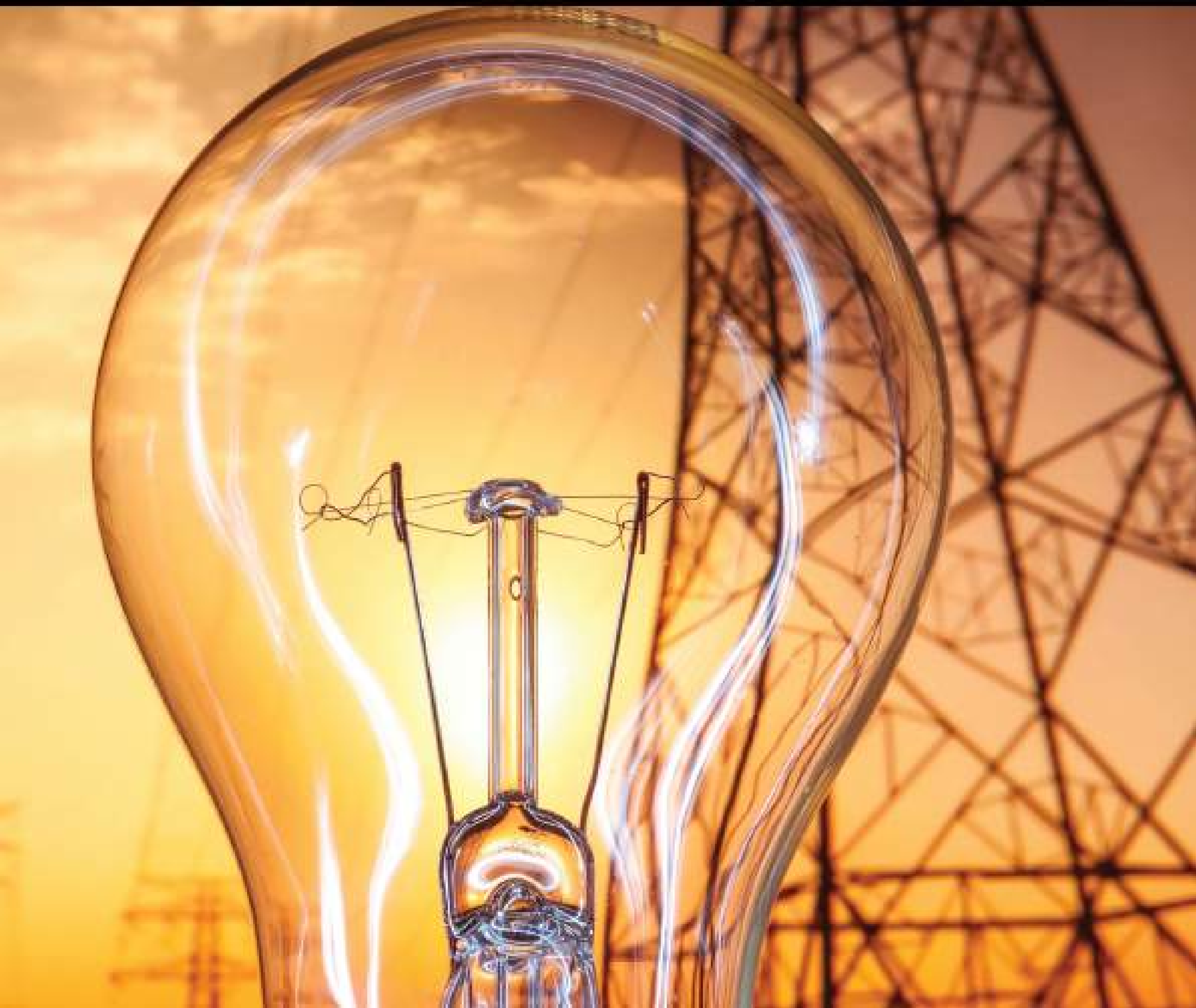
Digest of the HANDBOOK ON Electricity Regulation



This digest of the ***Handbook on Electricity Regulation*** (published by Edward Elgar in 2025) is prepared by:

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Preface

Electricity is at the core of modern societies and central to their future: the digitalisation of everything; Artificial Intelligence for countless applications.

It is because electricity is also the pioneer of one more "Energy Transition", even after a Trump 2 Administration's attempt to dismantle the Biden Administration's push for cleaner electricity and greater electrification.

All of you know, or have heard: "Petrostates" are not going to kill, or even defeat, "Electrostates". A new electricity age has arrived. China produced 1,850 TWh of wind and solar energy in 2024. And the EU and USA? Together, they produced 1,450 TWh. That total of 3,300 TWh is one-third more than the entire EU's electricity output.

Add to these "green electricity" fundamentals a global wave of storage batteries, electric vehicles, heat pumps, AI data centers, and building air conditioning, among others. Even Saudi Arabia is considering generating more electricity with renewables to spare its oil nationally (which it currently uses for 40% of its electricity generation) in order to sell more oil internationally.

But, but, but. Electricity is not as straightforward as oil or gasoline. It is a highly technical industry , both at the generation and the consumption stages. And, in between, from electricity generation to electricity consumption, there are thousands of components, equipment, and assets to operate. As a result, there are just as many decisions to take and to coordinate.

In 2021-2023, Paul Joskow, Michael Pollitt, and I, Jean-Michel Glachant, gave you all the keys to enter the electricity markets and master their options in another Handbook—the "Handbook on Electricity Markets". Today, we give you all the other keys: the keys to electricity regulation(s), to fully grasp how electricity still walks on two legs: its markets and its regulation(s)... everywhere in the world.

I am so proud to be doing this new Digest with Flora Kan! Our four legs are running at the forefront of the future, where electricity is performing this new incredible feat: "Another World Energy Transition: the electricity-based one".

Jean-Michel Glachant

Paris-Florence, 25 November 2025

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Glossary of Terms

Averch-Johnson (A-J) effect: The tendency of a regulated utility to over-invest in capital assets ("gold-plating") if its allowed rate of return is set higher than its actual cost of capital. This expands the utility's asset base, thereby increasing its total profits.

Behind the Meter (BTM): Refers to activities, technologies, and devices located on the customer's side of the utility meter. This includes customer-owned assets like rooftop solar panels, batteries, and electric vehicle chargers.

Benchmark Regulation (or Yardstick Regulation): A method of regulation where the performance of a utility in one region is used as a benchmark to set the allowed revenue for a company in another region. This creates incentives for cost reduction by comparing a firm to its peers.

Building-Block Approach: A standard method used by regulators to determine a utility's allowed revenue. It sums up various "building blocks", including operating expenses (Opex), depreciation (return of capital), and a return on the Regulatory Asset Base (RAB) (return on capital).

Capacity-based charges: Network tariffs based on a customer's maximum power demand (in kilowatts, kW) rather than their total energy consumption (in kilowatt-hours, kWh). This is considered more reflective of how a customer impacts network costs.

Command and Control Regulation: A direct approach to regulation where the regulator commands a utility to use specific technologies, meet certain service levels, and set prices at a dictated level. This approach is often ineffective due to the regulator's lack of perfect information.

Cost of Service Regulation (COSR) / Rate-of-Return (ROR) Regulation: A regulatory framework where prices are set to reflect the utility's actual costs of providing service, including operating expenses and a "fair" rate of return on its capital investments.

Cost-reflective Tariffs: Electricity rates designed to signal the true underlying costs of supplying energy, which often vary by time and location. These tariffs encourage more efficient energy consumption.

Critical-Peak Pricing (CPP): A type of time-varying rate where the on-peak price is substantially increased for a limited number of "critical" high-cost days per year to encourage significant demand reduction.

Distributed Energy Resources (DERs): Smaller-scale electricity-producing or-managing devices, typically located on the distribution grid or behind the meter. Examples include rooftop solar, battery storage, and electric vehicles.

Duck Curve: A phenomenon in electricity markets with high solar penetration, where net demand on the grid is very low or negative during the middle of the day (when solar generation is high) and then ramps up very steeply in the evening as the sun sets.

Earnings Sharing Regulation (ESR): A form of incentive regulation where a utility is required to share a portion of its earnings above a pre-determined threshold with its customers, usually through price reductions.

Energy Efficiency Paradox: The puzzle of why consumers and firms often fail to invest in energy efficiency measures that appear to be cost-effective (i.e., the future energy savings outweigh the upfront cost).

Flow-Based Market Coupling (FBMC): A sophisticated method for managing cross-border electricity trade in Europe that optimizes power flows across an entire regional grid model, rather than relying on simple bilateral capacity calculations for individual interconnectors.

Grid-Forming (GFM) Inverters: An advanced type of inverter that can actively create its own stable voltage and frequency reference, allowing it to operate like a traditional synchronous generator and provide grid stability services.

Grid-Following (GFL) Inverters: The standard type of inverter used in most renewable and battery systems today, which relies on detecting a strong, stable signal from the existing grid to synchronize its power output.

Incentive Regulation: The implementation of rules designed to motivate a regulated firm to use its private information and expertise to achieve the regulator's goals, such as cost efficiency and service quality. This contrasts with direct command-and-control regulation.

Inverter-Based Resources (IBRs): Electricity sources, such as solar, wind, and battery storage, that connect to the AC grid via a power electronic inverter. Their behavior is determined by software controls rather than physical properties.

Locational Marginal Pricing (LMP): A pricing system used in wholesale electricity markets where the price of energy varies by location (or "node") on the grid. Price differences between locations arise when transmission lines become congested, signaling the need for new investment.

Marginal Loss Factors (MLFs): Coefficients applied to the wholesale spot price at each connection point in Australia's NEM to account for the marginal cost of power losses in the transmission network. They provide granular locational price signals to generators.

Natural Monopoly: An industry where it is more cost-effective for a single firm to serve the entire market than for multiple firms to compete, typically due to massive infrastructure requirements and economies of scale. Electricity transmission and distribution networks are classic examples.

Price Cap Regulation (PCR): A form of incentive regulation where the regulator sets a maximum price a utility can charge for a fixed period. The utility is then incentivized to reduce its costs below that price cap, as it can keep the savings as profit.

Prosumager: An electricity customer who not only produces (prosumer) and consumes energy but also actively manages and stores it, often using a combination of solar panels, batteries, and controllable loads like EVs.

Regulatory Asset Base (RAB) / Regulatory Asset Value (RAV): The value of a utility's capital assets as recognized by the regulator for the purpose of setting prices. Utilities earn an allowed rate of return on this base.

Regulatory Investment Test for Transmission (RIT-T): A formal, public cost-benefit analysis required for all significant new network investments in Australia, designed to identify the option that maximizes the net economic benefit to the market.

Regulatory Lag: The period between formal rate cases in cost-of-service regulation. During this time, a utility's prices are fixed, which creates an incentive for the utility to reduce its costs to increase its profits until the next rate case.

Single-Buyer Model: A market structure, common in developing countries, where a single state-owned utility buys power from multiple independent power producers (IPPs), typically through long-term contracts.

Synchronous Machines (SMs): Large, rotating generators found in conventional power plants (thermal, nuclear, hydro). Their physical rotating mass provides inertia, which is a key source of stability for the power grid.

Time-of-Use (TOU) Rates: Retail electricity tariffs where the price per kWh varies by time of day (e.g., on-peak and off-peak periods) to better reflect the underlying cost of generation and encourage customers to shift their usage to lower-cost times.

Totex Regulation: An approach to regulation that focuses on a utility's total expenditure (Totex), which is the sum of capital expenditure (Capex) and operating expenditure (Opex). This removes any regulatory bias towards either capital or operational solutions, encouraging the most efficient overall choice.

Unbundling: The separation of the monopoly parts of the electricity sector (transmission and distribution networks) from the potentially competitive parts (generation and retail).

Virtual Power Plant (VPP): An aggregation of numerous individual behind-the-meter assets (like batteries or smart appliances) that are bundled together and controlled by software to act as a single, larger resource that can provide services to the grid.

Acronyms

AEMC: Australian Energy Market Commission - The independent rulemaking body for Australia's NEM.

AEMO: Australian Energy Market Operator - The independent market and system operator in Australia.

AER: Australian Energy Regulator - The economic regulator for the transmission and distribution networks in Australia's NEM.

BTM: Behind the Meter.

COSR: Cost of Service Regulation.

DNO: Distribution Network Operator - The company that owns and operates the regional electricity distribution network, for example in Great Britain.

DSO: Distribution System Operator - The entity responsible for operating the local electricity distribution grid. Its role is evolving from a passive network manager to an active facilitator of DERs.

ESO: Electricity System Operator - The entity responsible for the real-time, minute-by-minute operation of the transmission system.

EU: European Union.

EV: Electric Vehicle.

FERC: Federal Energy Regulatory Commission - The US federal agency that regulates interstate transmission of electricity and wholesale power markets.

GB: Great Britain.

IBR: Inverter-Based Resource.

IOU: Investor-Owned Utility - The most common type of utility in the US, owned by private shareholders.

IRA: Inflation Reduction Act - A 2022 US law providing major financial incentives for clean energy.

ISO: Independent System Operator - A non-profit organization that independently operates a regional transmission grid and sometimes a wholesale power market.

LMIC: Lower- and Middle-Income Country.

NEM: National Electricity Market - The wholesale electricity market covering the eastern and south-eastern states of Australia.

NGA: Natural Gas Act - A US federal law governing interstate natural gas, which could potentially be a model for regulating hydrogen pipelines.

OFTO: Offshore Transmission Owner - In Great Britain, a company that owns and operates the transmission assets connecting an offshore wind farm to the onshore grid, typically chosen through a competitive auction.

PBR: Performance-Based Regulation - A broad category of regulation that links a utility's earnings to its performance against specific metrics, moving beyond just cost-of-service principles.

PCR: Price Cap Regulation.

PPA: Power Purchase Agreement - A long-term contract to buy electricity from a specific generator at a pre-agreed price.

RAB: Regulatory Asset Base.

RIIO: Revenue = Incentives + Innovation + Outputs - The current regulatory framework in Great Britain for energy networks, designed to encourage efficiency, innovation, and the delivery of specific performance outcomes.

ROR: Rate-of-Return (Regulation).

RTO: Regional Transmission Operator - Similar to an ISO, an RTO operates the transmission grid and wholesale markets over a large multi-state region in the US.

SERC: State Electricity Regulatory Commission - The regulatory body for the power sector at the state level in India.

T&D: Transmission and Distribution.

TNUoS: Transmission Network Use of System - The name for transmission tariffs in Great Britain, which are strongly differentiated by geographic location to signal the cost of using the network.

TSO: Transmission System Operator - The entity responsible for transporting energy on the high-voltage transmission network.

US: United States.

VPP: Virtual Power Plant.

WACC: Weighted Average Cost of Capital - The blended cost of a utility's debt and equity financing, used to determine the allowed rate of return on its assets.

Chapter 1: Introduction to the Handbook on Electricity Regulation

Jean–Michel Glachant, Paul L. Joskow and Michael G. Pollitt

This book is a companion volume to the *Handbook on Electricity Markets*, which focused on the evolution and challenges of wholesale electricity markets, particularly with the integration of intermittent renewable energy. This volume shifts the focus to the formally regulated segments of the electricity sector: network regulation, the functions of economic regulators, and the regulation of retail electricity.

The content is structured into three distinct parts. The first part establishes the current state of electricity regulation, examining its foundations and recent reforms. The second part looks towards the future, exploring the regulatory implications of the path to net zero carbon emissions. The third part broadens the geographical scope to consider the unique regulatory landscapes of non-OECD countries.

Parts I and II concentrate primarily on the United States (US), Great Britain (GB), Australia, and the European Union (EU). These jurisdictions have been selected because they are home to the oldest and most sophisticated frameworks for the economic regulation of electricity. Part III then turns its attention to the significant and evolving regulatory environments in India, China, and the broader category of lower- and middle-income countries (LMICs).

The fundamental challenge of electricity regulation is to balance the control of monopoly prices with the promotion of efficiency, all while leveraging competition wherever it is viable. The rise of competitive wholesale and retail electricity markets has increasingly focused regulatory attention on transmission and distribution networks, which are typically separated from the more competitive parts of the sector. However, the extent of this separation varies; while Europe and Australia have established clear unbundling of networks, this remains an ongoing process in many other parts of the world.

Looking ahead, this book examines how regulation must adapt to the changing characteristics of the power system as driven by net zero targets in the US and Europe. This includes exploring specific challenges such as developments 'behind the meter' (e.g., rooftop solar and batteries), fostering innovation within the regulated sector, and managing the profound uncertainty surrounding the future evolution of the energy industry. Two critical new areas of regulation necessitated by the net zero transition are also addressed: the regulation of green hydrogen markets and networks, and the regulation of electric vehicle (EV) charging infrastructure.

Several overarching themes emerge from the comprehensive analysis presented by the contributing authors:

First, the history of electricity regulation offers valuable lessons. It demonstrates that well-designed **incentive regulation** is a powerful tool for driving down costs while encouraging the quality of service and investment that society values.

Second, the regulation of **transmission** is becoming increasingly complex. This is due to the practical difficulties of building new onshore infrastructure and the growing need for clear cost signals that guide the optimal location of both generation and demand to minimise system costs.

Third, the regulation of **distribution** can be adapted to improve service quality and respond to user preferences for both generation and demand. However, it is crucial to design this regulation carefully to avoid incentivising over-investment and to encourage the optimal substitution of operational expenditures for traditional capital investments where it is more efficient.

Fourth, ambitious **net zero targets** are placing significant strain on existing incentive-based regulatory systems. These systems were often designed for mature networks where controlling costs was the primary objective. In the new era, mechanisms such as automatic adjustments, dedicated innovation funding, and more responsive regulatory approaches are becoming increasingly important.

Fifth, achieving net zero may require fundamental changes to existing **institutional arrangements**. Many current structures of network ownership, system operation, and regulation were established before the net zero era and may need to be reformed to align with decarbonisation goals.

Finally, many **developing countries** continue to face the foundational challenge of establishing effective, independent regulation. This basic level of governance is essential to attract the massive private and public investment needed to deliver electricity at reasonable costs, with acceptable service quality, and with minimal environmental impact. While the principles of good regulation are universal, their application in developing countries requires navigating unique political and economic contexts.

This digest aims to provide decision-makers with a comprehensive overview of the key principles, challenges, and future directions in electricity regulation, drawing from the rich insights and detailed analysis contained within the full Handbook.

Part I: Foundations of Electricity Regulation and Recent Reforms

Chapter 2: Designing Incentive Regulation in the Electricity Sector

By David P. Brown and David E.M. Sappington

The Rationale for Regulation

In many sectors, competition is the primary source of consumer protection. Intense competition to attract customers compels suppliers to offer high-quality services at prices that reflect production costs, limiting the suppliers to a normal profit in the long term. Competition also provides a powerful incentive for continuous innovation in both cost reduction and service quality enhancement.

However, in industries characterised by massive infrastructure requirements and significant economies of scale—so-called natural monopolies—direct competition can be prohibitively expensive. The electricity transmission and distribution (T&D) network is a leading example. Constructing multiple, duplicative T&D networks to foster competition would require consumers to finance the immense costs of building and operating redundant infrastructure. When these duplicative costs are exceptionally large, consumers are better served by well-designed regulation of a monopoly network supplier than by direct competition among multiple network suppliers.

When a natural monopoly prevails, a regulator optimally authorises a single T&D network to operate as a monopoly within a specific geographic area, and then oversees the monopoly's activities. The primary goal of this regulation is to replicate the discipline that would prevail if competitive pressures were present. In an ideal world, a regulator could simply command the monopoly to use the most efficient technology, deliver the optimal level of service quality, and set prices that allow for only a normal profit under efficient operation. This "command and control" approach, however, requires the regulator to have perfect information about feasible technologies, efficient costs, consumer preferences, and the precise magnitude of a normal profit.

In reality, regulators seldom have such perfect information. A regulated firm typically is better informed than the regulator about both prevailing industry conditions and its own capabilities. This information asymmetry is a core rationale for **incentive regulation**. Incentive regulation can be defined as the implementation of rules designed to induce a regulated firm to use its superior knowledge of industry conditions to achieve the regulator's goals. Incentive regulation seeks to harness the firm's knowledge and self-interest to serve the public interest, rather than simply commanding the firm to do so.

Fostering Competition Where Possible

Because it is so difficult to replicate market discipline, it is generally advisable to promote direct competition in segments of the industry where direct competition is not prohibitively costly. This principle has guided the restructuring of the electricity industry in many parts of the world.

Historically, a single vertically integrated provider (VIP) often controlled the generation, transmission, and distribution of electricity. Although T&D networks are natural monopolies, the generation of electricity exhibits relatively modest scale economies. A single utility might operate multiple power plants that, in principle, could be owned and operated by different, competing entities. Consequently, many jurisdictions have required utilities to sell their generation assets or to legally separate their generation and T&D operations. These reforms have facilitated the development of competitive wholesale electricity markets, where multiple generators compete to supply electricity to large industrial customers and to the load-serving entities that deliver electricity to retail customers. Complementary reforms have promoted competition among retail suppliers of electricity. Although the reforms have promoted competition, they have not eliminated the need for regulation entirely. In many settings, individual generators and retailers maintain the ability to exercise market power, necessitating regulatory oversight and control to ensure more competitive outcomes.

Mechanisms other than the direct, ongoing, isolated control of a single monopoly supplier can sometimes be employed to mimic competitive pressures on the monopoly T&D network:

- **Competition for the Market:** This mechanism involves periodically allowing potential operators to bid for the right to run the T&D network. In theory, the threat of losing the auction might impose strong discipline on the incumbent supplier. In practice, such "competition for the market" faces significant challenges. The pool of qualified bidders may be small, which can render the competition weak and ineffective. It is also difficult to write a comprehensive long-term contract that foresees all future contingencies and specifies all relevant performance dimensions. Furthermore, the risk of losing the franchise could discourage the incumbent from making necessary long-term investments. For these reasons, this mechanism is rarely employed in practice.
- **Yardstick (or Benchmark) Regulation:** This mechanism employs the performance of T&D companies in other regions as a benchmark for the performance that a given company should achieve. When a company’s authorised revenue reflects the costs achieved by its peers rather than its own costs, the firm benefits financially when it reduces its own costs. Such yardstick regulation can thereby provide strong incentives for cost reduction. However, yardstick regulation requires careful implementation. It is imperative to control for exogenous differences in operating conditions that companies face (e.g., customer density, terrain, input prices) to ensure that established benchmarks are fair and achievable. Sophisticated econometric techniques can help to establish appropriate benchmarks when reliable, comprehensive data is available.

Core Principles of Incentive Regulation Design

When designing incentive regulation for a T&D company, a regulator seeks to maximise consumer welfare by securing low prices and high-quality service, while ensuring the company has a reasonable opportunity to earn at least a normal profit. Such opportunity is vital to ensure the firm can attract the capital it needs to finance essential investment. The optimal regulatory policy depends on the regulator's information and the policy tools at its disposal.

- **Cost of Service Regulation (COSR):** In a hypothetical world where the regulated firm works diligently to operate efficiently, the regulator could simply set prices to reflect the firm's realised costs. This is the essence of COSR (also known as rate-of-return regulation). However, in reality, privately owned firms typically seek to maximize profit, so they have little incentive to operate efficiently if all achieved cost savings are immediately passed on to consumers in the form of lower prices.

- **Price Cap Regulation (PCR):** PCR is designed to sever for a specified period of time the direct link between a firm's costs and the prices set for its products. At the start of a price cap plan (which often lasts for approximately five years), the regulator specifies the maximum prices the firm can charge for its products. The maximum prices often reflect an estimate of what efficient costs *should* be. During the plan, the firm is allowed to retain any cost savings it achieves. This opportunity can create strong incentives for efficiency. At the end of the period, the price cap is "reset" to reflect the newly achieved level of efficiency, thereby passing the benefits of efficiency gains on to consumers. PCR is most effective when the regulator can predict the potential for cost reduction reasonably well, and when the regulator can credibly commit to allow the firm to earn substantial profit during the prevailing regulatory plan if the firm outperforms expectations.
- **Earnings Sharing Regulation (ESR):** ESR is an alternative to PCR that can be preferable to PCR when the regulator faces substantial uncertainty about the firm's potential for cost reduction. Under ESR, the firm is required to share a portion of its earnings above a certain threshold with consumers, typically through price reductions. This sharing has the potential to protect consumers by limiting exceptionally high profits for the firm. However, the sharing can harm consumers because it reduces the firm's incentive to achieve efficiency gains by limiting the firm's reward for such gains.
- **Menus of Regulatory Plans:** Instead of imposing a single plan, a regulator can sometimes secure greater benefits for consumers by allowing the firm to choose one regulatory plan from a carefully designed menu of plans. For example, the firm might be permitted to choose between a price cap plan with a low maximum price and an earnings sharing plan with a higher maximum price. This choice can induce the firm to employ its superior knowledge of industry conditions to implement the plan that ensures gains for the firm and for consumers alike.

Practical Considerations in Implementation

- **Plan Duration:** The length of a regulatory plan affects its performance. A longer plan strengthens the firm's incentive to reduce its costs and to undertake long-lived investments because the firm can retain the associated benefits for a longer period of time. However, a longer plan requires consumers to wait longer before they realise the benefits of achieved efficiency gains in the form of lower prices. Longer plans (e.g., five or more years) can be advisable when the potential for cost reduction is pronounced and relatively predictable.
- **Re-openers:** Most long-term plans include "re-opener" clauses. These clauses specify the conditions under which the plan can be modified before its scheduled termination. Typically, re-openers are reserved for major, unanticipated, and exogenous events (i.e., events beyond the firm's control) that have a substantial financial impact, such as a costly new government mandate.
- **Service Quality:** Because strong incentives for cost reduction can encourage a firm to reduce service quality, incentive regulation plans generally impose explicit quality standards. These standards are typically accompanied by a system of financial rewards for exceeding targets and penalties for failing to meet them. By setting these rewards and penalties to reflect the value consumers place on service quality, the regulator can motivate the firm to deliver efficient levels of service quality.
- **Capital Investment:** T&D networks require significant ongoing investment. Regulation must provide credible assurances that firms will be able to recover the costs of prudent investments. To discourage firms from exaggerating their investment needs (as they may be tempted to do under cost of service regulation), regulators sometimes authorize higher allowed rates of return for firms that successfully

deliver high quality service to customers with relatively low levels of capital investment.

- **Promoting Distributed Energy Resources (DERs):** The rise of DERs like rooftop solar and customer-owned storage presents new regulatory challenges. Cost of service regulation can create a bias towards capital-intensive utility-owned solutions over DERs, which may be classified as operational expenditures. To limit this bias, some regulators have moved to "Totex" regulation, which rewards reductions in capital expenditures and operational expenditures more symmetrically. Other means to encourage the adoption of efficient DERs include allowing the utility to retain a share of the cost savings generated by non-utility DER projects.

Empirical studies confirm that incentive regulation can be effective in practice. Incentive regulation has been shown to induce T&D companies to secure cost reductions and productivity gains. The evidence on service quality is more mixed. However, incentive plans that include explicit financial rewards for exceptional service quality and explicit penalties for sub-standard quality often induce higher levels of service quality.

Chapter 3: Cost-of-Service Regulation of Electricity Distribution Services in the US

By Paul L. Joskow and Richard Schmalensee

The US Regulatory Landscape

This chapter details the practical application of cost-of-service regulation (COSR), also known as rate-of-return (ROR) regulation, by public utility commissions in the United States to set the prices for electricity distribution services. This regulatory framework is foundational in the US and applies to investor-owned utilities (IOUs), which serve nearly three-quarters of all retail consumers. While the electricity sector has undergone significant restructuring, COSR remains the bedrock principle for regulating both distribution and transmission networks.

The structure of the US electric power industry is diverse and often misunderstood. It has not been fully restructured. Many utilities remain vertically integrated to some degree, involved in generation, transmission, and distribution. Full retail competition is only available in about a dozen states. Ownership is also varied, including IOUs, publicly-owned municipal utilities, and customer-owned cooperatives. COSR is the primary mechanism for IOUs, and it also forms the basis for newer performance-based regulation (PBR) schemes that are slowly being adopted.

Regulatory responsibility in the US is split. State public utility commissions regulate local distribution rates, the transmission services bundled for a utility's retail customers, and in a majority of states which have not fully restructured, generation services from plants owned by the distribution utility. The federal government, through the Federal Energy Regulatory Commission (FERC), regulates the terms and conditions in mandatory open access transmission tariffs, depending in part on whether transmission service has been fully unbundled from distribution. On average, distribution services account for about 26% of a customer's bill, with transmission adding another 12%. This combined 38% for delivery services is expected to grow as significant investment is needed to support decarbonisation goals, such as accommodating electric vehicles and heat pumps.

Rationale and Governance

The traditional rationale for regulating electricity prices is the concept of **natural monopoly**. A firm has natural monopoly characteristics in a geographic area when it is generally less costly for a single firm to provide network services in a given geographic area than for multiple firms to build duplicative infrastructure. However, an unregulated monopoly would have significant market power, allowing it to charge excessive prices. Regulation aims to mitigate this market power while protecting the long-lived, sunk investments of the utility from expropriation, thereby preserving the incentive to invest, and to ensure that the costs utilities propose to include in the prices they charge are cost effective --- just and reasonable from a legal perspective.

While it was once believed that all segments of the industry (generation, transmission, distribution) were natural monopolies, it is now recognized that generation can be competitive. This has led policymakers to require vertically integrated utilities to restructure by separating ownership of generation from distribution and transmission. In these cases, generation suppliers operate in competitive markets which

T&D networks continue to be treated as geographic natural monopolies, making them the primary focus of state commission regulation.

In the US, the dominant governance structure for IOUs is the **independent regulatory commission**, a quasi-judicial body of three to seven commissioners either appointed by the governor of each state or elected. The members of FERC are nominated by the president and approved by congress. While legally independent, they are not immune to political influence, as commissioners are often political appointees and their budgets are controlled by legislatures. Recent actions by President Trump have challenged this independence at the federal level and the Supreme Court will review challenges to these actions in 2026.

Cost-of-Service Regulation in Practice: The Formal Rate Case

Electricity distribution rates are set through a formal, public process called a **general rate case**. The utility typically initiates the process by proposing new rates. Other parties, such as consumer advocates, industrial customer groups, and environmental organizations, can participate as "intervenors". The process is evidence-based, involving written testimony and sometimes oral hearings, and culminates in a detailed decision by the commission.

The process hinges on determining the utility's **revenue requirement**, which is the total amount of money the utility is allowed to collect from customers over a specific period (usually a year). The revenue requirement is calculated based on data from a designated "test year" and is the sum of three main components:

- **Operating Expenses (O&M):** These are the day-to-day costs of running the utility, including labor, fuel, materials, maintenance, and taxes. The regulator reviews these costs for "reasonableness" and can disallow any expenses deemed imprudent.
- **Capital-Related Costs:** These represent the cost of the capital assets (poles, wires, transformers) used to provide service. This component is calculated as:
  - **Return *on* capital:** The allowed rate of return (r) multiplied by the value of the utility's **Regulatory Asset Base (RAB)**. The RAB, or "rate base", is the value of the utility's assets recognized for regulatory purposes. In the US, this is generally calculated as the original cost of the assets minus accumulated depreciation.
  - **Return *of* capital:** The annual **depreciation** (D) on the assets in the rate base. This is treated as an operating expense that allows the utility to recover its initial investment over theassumed life of the assets.
- **Other Costs (F):** This includes items like property taxes, income taxes and franchise fees.

The revenue requirement formula is thus:

$R_t = O\&M_t + D_t + (r_t \times RAB_t) + F_t$

A key and often contentious part of the rate case is determining the **allowed rate of return (r)**. This is calculated as the weighted average cost of capital (WACC), taking into account the utility's mix of debt and equity financing. The cost of debt is relatively straightforward (based on interest rates on existing bonds), but the cost of equity must be estimated using financial models and is a frequent point of dispute. The legal standard, established in the 1944 *Hope* Supreme Court decision, is that the return should be sufficient to maintain the utility's financial integrity and attract necessary capital, but no more than that.

From Revenue Requirement to Customer Rates: Rate Design

Once the total revenue requirement is established, the second phase of the rate case is **rate design**. This involves two steps:

1. **Cost Allocation:** The total revenue requirement is allocated among different customer classes (e.g., residential, commercial, industrial) based on studies that estimate the cost of serving each class. Because many costs are shared (joint or common), this allocation process involves considerable regulatory judgment.
2. **Tariff Structure:** Within each class, the structure of the rates (tariffs) is determined. Traditionally, for residential customers, this has been a simple two-part tariff consisting of a small monthly fixed "customer charge" and a volumetric charge per kilowatt-hour (kWh). The rates are designed so that, based on forecast electricity usage, the total revenue collected will match the allowed revenue requirement.

The Performance and Incentive Properties of COSR

For much of the 20th century, COSR performed reasonably well in an environment of technological progress and economies of scale, leading to declining costs. However, economists have long identified potential inefficiencies.

The most famous critique is the **Averch-Johnson (A-J) effect**, which posits that if the allowed rate of return is set higher than the utility's actual cost of capital, the regulatory constraints is always binding, and the regulator cannot disallow inefficient costs, the firm has an incentive to over-invest in capital assets (i.e., expand its rate base) to increase its total profits. This is often referred to as a "capital bias" in rate of return regulation.

In practice, the pure A-J model is an oversimplification. The real world of COSR is characterized by **regulatory lag**. Rate cases are not continuous; there can be several years between them. During the period of "lag" between rate cases, the utility's prices are fixed. This creates a de facto incentive for efficiency: if the utility can reduce its costs during the lag period, it can keep the extra profits until the next rate case, when the new, lower costs are incorporated into the revenue requirement. This lag acts as a feature, not a bug, providing a performance incentive that is absent in a pure, continuously adjusted COSR model. In addition, regulators can disallow costs that they determine to be inefficient.

Despite the effect of regulatory lag, COSR is still believed to lead to inefficiencies absent addition "incentive regulation" mechanisms. A primary issue is the bias towards **owning capital assets** rather than procuring services from third parties. Expenditures on utility-owned capital go into the rate base and earn a regulated return, whereas payments for third-party services are often treated as a simple operating expense pass-through with no profit margin. This creates a disincentive for utilities to use potentially more efficient non-utility solutions, a key challenge in integrating distributed energy resources.

- While the US has been slower than other jurisdictions to adopt more explicit incentive mechanisms, there is a growing trend towards complementing traditional COSR with various forms of **performance-based regulation (PBR)**. These new mechanisms, driven by the expanding responsibilities of distribution utilities in a decarbonising world, include multi-year rate plans, performance incentive mechanisms (PIMs) targeting specific outcomes like reliability or DER integration, and revenue decoupling mechanisms. However, even within these advanced PBR frameworks, the principles of COSR remain a crucial complement, forming the basis for setting the initial revenue benchmarks and for true-up proceedings.

Chapter 4: Regulated Distribution Sector Facing the Future: The GB Experience

By Cloda Jenkins

The Evolution of DNO Regulation in Great Britain

In Great Britain (GB), electricity distribution services are provided by 14 privately owned, regional monopoly companies known as Distribution Network Operators (DNOs). Since privatisation in 1990, these DNOs have been subject to economic regulation, which has evolved significantly over the past three decades in response to changing economic conditions, technological advancements, and shifting policy priorities, particularly the drive towards a low-carbon energy system.

The initial regulatory framework adopted at privatisation was **RPI-X**, a form of price cap regulation. Under this system, the DNO's allowed revenue was permitted to change each year by the rate of the Retail Price Index (RPI) minus an "X-factor", which represented a target for productivity improvements. This framework was periodically reviewed, typically every five years, in a process known as a Distribution Price Control Review (DPCR).

Over time, the RPI-X methodology became increasingly complex. The regulator, the Office of Gas and Electricity Markets (Ofgem), introduced more sophisticated tools to set the X-factor, including benchmarking DNOs against each other to assess efficient cost levels. As concerns grew that the strong incentive to cut costs might lead to a decline in service quality, Ofgem integrated explicit incentives for quality of service, such as reliability, directly into the price control.

By 2008, there was a growing consensus that the RPI-X framework, originally designed to drive efficiency in mature industries, might not be fit for purpose to deliver the massive investment and innovation required for a low-carbon energy sector. This led to a major two-year review, known as "RPI-X@20", which culminated in the decision to introduce a new framework: **RIIO**.

The RIIO Framework: Revenue = Incentives + Innovation + Outputs

The RIIO framework, introduced for DNOs for an eight-year period starting in 2015 (RIIO-ED1), was an evolution of RPI-X, not a revolution. It retained the core principle of an upfront, fixed-period price control where allowed revenues are set based on a forecast of efficient costs. However, RIIO placed a much stronger and more explicit emphasis on incentives (I), innovation (I), and the delivery of a broad range of outputs (O).

The key features and innovations of the RIIO framework include:

- **A Focus on Outputs:** Rather than just focusing on costs, RIIO defines a clear set of outputs that DNOs are expected to deliver across several categories, including customer satisfaction, safety, reliability, environmental impact, and connections. Many of these outputs are linked to specific financial rewards for outperformance and penalties for underperformance. This ensures that cost-cutting does not come at the expense of the services that customers and wider society value.
- **Totex Regulation:** A significant innovation was the move away from separate assessments of operating expenditure (Opex) and capital expenditure (Capex). RIIO focuses on total expenditure (**Totex**). This approach is designed to remove the bias towards capital-intensive solutions that can

exist under traditional regulation. By incentivising DNOs to find the lowest-cost solution in Totex terms, it encourages them to make efficient trade-offs between capital and operational solutions. For example, a DNO might be incentivised to pay a third party for demand response services (an Opex solution) if it is cheaper than building a new substation (a Capex solution) to manage local network constraints.

- **Dedicated Innovation Funding:** Recognising that the transition to a low-carbon system requires new technologies and business models, RIIO includes specific funding mechanisms to encourage innovation. DNOs receive a Network Innovation Allowance to fund smaller projects and can also compete for funding for larger, strategic projects through a Network Innovation Competition. This ring-fenced funding helps to de-risk innovation and encourages a culture of experimentation that might otherwise be stifled by short-term cost-saving pressures.
- **Enhanced Stakeholder Engagement:** RIIO places a strong emphasis on DNOs engaging with their customers and stakeholders to develop their business plans. DNOs are expected to consult extensively to ensure their investment proposals reflect the priorities of the communities they serve. Well-justified plans that demonstrate strong stakeholder support are rewarded with lighter-touch scrutiny from the regulator, a process known as "fast-tracking" in the first RIIO period.
- **Longer Price Control Periods:** The first RIIO period for distribution was set for eight years, a significant increase from the typical five-year RPI-X cycle. The rationale was to encourage a more long-term strategic focus from companies, giving them greater certainty to plan and deliver major, multi-year investment projects.

Outcomes and Lessons Learned

The experience of RPI-X and RIIO in GB provides valuable lessons on the strengths and limitations of incentive regulation.

- **Performance Improvements:** Since privatisation, the regulatory frameworks have successfully driven significant improvements in performance. DNO charges have fallen in real terms, productivity has improved, and key quality of service metrics, such as the duration and frequency of supply interruptions, have seen substantial improvements.
- **The Challenge of Information Asymmetry and Windfall Profits:** A persistent challenge for any forward-looking incentive framework is setting the targets and allowances at the right level. Because the regulator has less information than the company, there is a risk that cost forecasts are too high or output targets are too low. This was a notable issue during the RIIO-ED1 period, where DNOs consistently outperformed their targets and earned returns for shareholders that were significantly higher than the baseline allowed by the regulator. While this demonstrates that the incentives were working to some extent, critics argued that the high returns did not reflect genuinely exceptional performance but rather overly generous initial targets, undermining the credibility of the framework.
- **The Trade-off of Long Control Periods:** The experience with the eight-year RIIO-ED1 period highlighted the trade-off between providing long-term certainty and the risk of "getting it wrong". The high returns earned by DNOs suggested that the downside of inaccurate long-term forecasting outweighed the benefits of the longer period. Consequently, for the second distribution price control (RIIO-ED2, from 2023), Ofgem reverted to a five-year period.
- **The Need for Adaptability:** The evolution from RPI-X to RIIO, and the subsequent refinements for RIIO-ED2, demonstrate that regulation is not a static exercise. Regulators must be adaptable, learning from experience and updating their frameworks in response to revealed information and the changing context. For RIIO-ED2, Ofgem introduced several changes to address the lessons from the first period. These included setting tougher targets, recalibrating financial incentives to focus

more on penalising underperformance than rewarding outperformance, and introducing an overall cap on the total returns a company can earn to protect consumers from excessive windfall gains.

In conclusion, the GB experience shows that incentive-based regulation can be a powerful driver of efficiency and output delivery. However, it is a continuous search for a framework that is "good enough", not a magic bullet. The RIIO model represents a sophisticated attempt to balance competing objectives, but it cannot eliminate the fundamental challenge of information asymmetry. The key is to maintain a stable and credible framework that encourages long-term investment while remaining adaptable enough to correct for past errors and respond to the evolving needs of the energy transition.

Chapter 5: Regulated Distribution Sector Facing the Future: Trends in the European Union

By Christine Brandstätt and Jean-Michel Glachant

The Transforming Role of Distribution Grids in the EU

Across the European Union, the electricity distribution sector is in the midst of a profound transformation, driven by the overarching policy goals of decarbonisation, decentralisation, and digitalisation. The traditional role of the Distribution System Operator (DSO) as a passive manager of one-way power flows from the transmission system to consumers is becoming obsolete. Instead, DSOs are facing a future where they must actively manage complex, multi-directional energy flows and facilitate a host of new services and technologies at the local level.

This transformation began with the liberalisation of EU energy markets in the 1990s, which mandated the **unbundling** of monopoly network activities from competitive generation and retail businesses. Initially, regulation focused on driving efficiency and reducing the costs of the established DSOs. This was achieved through incentive regulation and benchmarking, which applied downward pressure on costs.

However, the policy landscape has shifted dramatically. The EU's strong commitment to decarbonisation through electrification—encompassing transport, heating, and industrial processes—is set to cause a tremendous increase in electricity consumption. Simultaneously, there is a massive rise in **distributed generation**, particularly from wind and solar resources connected at the distribution level. This influx of intermittent, decentralised energy fundamentally challenges the traditional "fit and forget" approach to network planning.

The regulatory challenge has therefore evolved from simple cost reduction to facilitating a cost-increasing transformation of the network. The focus is now on enabling the integration of renewables and leveraging the potential of digitalisation, which requires significant new investment in the grid. Regulators and policymakers across the EU are grappling with how to incentivise this necessary investment while maintaining discipline on efficiency and protecting consumers. This chapter uses the experiences of Germany and the Netherlands to illustrate two different approaches to this challenge: one of incremental change, and one of radical reinvention.

Germany: An Incremental Transformation

Germany's distribution sector is highly fragmented, with over 800 DSOs, and is facing significant stress from high levels of distributed generation. The regulatory response has been largely incremental, adapting existing rules to manage new challenges.

- **Revised Grid Dimensioning:** A key early adjustment was to relax the rule that grids must be built to accommodate 100% of potential feed-in from renewables. Recognising that the highest generation peaks from wind and solar occur rarely, German regulation now allows DSOs to plan their grid expansion for only 97% of the annual feed-in. This condones a small amount of curtailment (up to 3%) but avoids the very high marginal cost of building network capacity that would sit idle for most of the year, thereby reducing costs and speeding up connections.
- **Adjusting Network Tariffs:** With the rise of "prosumers" (consumers who also produce electricity,

e.g., with rooftop PV), a challenge emerged for fair cost recovery. Prosumers reduce their net withdrawal from the grid, and under a purely volumetric tariff, their contribution to fixed network costs falls, even though they still rely on the grid for backup. In response, many German DSOs have increased the fixed component of their network tariffs. This ensures that prosumers still contribute a minimum amount to the upkeep of the network they use, preventing an excessive cost-shift to non-prosuming customers.

- **Tariffs for Flexible Loads:** To tap into the flexibility potential of new loads like electric vehicles and heat pumps, Germany is refining its special network tariffs for controllable loads. A new proposal allows DSOs to partially curtail these loads as a temporary measure until the grid is reinforced. In return, eligible consumers can choose from several compensation options, including a fixed annual rebate or a percentage reduction on their volumetric charge, incentivising them to offer their flexibility to the system.
- **Sandboxes for Flexibility Markets:** The German government has supported large-scale research and demonstration projects (such as the SINTEG programme) to experiment with market-based mechanisms for integrating flexibility. These "sandboxes" offer temporary exemptions from certain regulations to test new platforms and market designs for trading flexibility at the local level, providing valuable experience for future market development.

The Netherlands: The Challenge of Leapfrogging

The Netherlands presents a contrasting case where the pace and scale of change are forcing a more radical reinvention of the distribution grid. Despite having a more centralised structure with only six DSOs, the grids are already significantly congested. This is due to a rapid increase in solar PV penetration, driven by subsidy changes, and a highly ambitious government strategy for deep electrification, breaking from the country's long history as a natural gas giant.

The existing distribution system was not designed for electrical heating and is struggling to keep up with new connection requests for both generation and large loads. The situation is so severe that the system cannot simply evolve incrementally; it needs to **leapfrog** to a new state. The grid requires a radical transformation of its architecture to meet the country's 2030 and 2050 climate targets. This challenge has led to a number of innovative and "unorthodox" responses:

- **Congestion Management:** With grid capacity unavailable in many areas, the regulator has introduced new rules to lower the threshold for participation in congestion management. This includes bilateral "Capacity Limitation Contracts" and the introduction of Congestion Management Service Providers to aggregate flexibility.
- **Non-Firm Connections:** To manage the queue of new connections, proposals are being developed for "non-firm" connection agreements. Under this model, a new user can connect but has no guarantee of access. Their connection can be fully blocked when the local grid is congested, in exchange for significantly reduced grid tariffs.
- **A Paradigm Shift in Access:** The situation has become so critical that the Dutch government has acknowledged that universal and unlimited access to electricity supply is no longer the default. Measures are being announced to increase grid tariffs for existing firm connections and reduce them for non-firm or group contracts, making flexible access the new standard for all users, not just new ones.
- This radical approach is facilitated by the fact that the Dutch grids are publicly owned, with the national government guaranteeing the full financing for the necessary leapfrogging investments. The main constraints are not financial but physical: a lack of skilled personnel, manufacturing capacity for equipment, and available land. The primary incentive for the DSOs is intense public and political

pressure to implement the national priority of decarbonisation. This is driving the Dutch system into the new world of "transactive energy", where access rights and duties are dynamically adapted to hard physical constraints.

Towards a European Layer of Distribution Regulation

- While national responses vary, there is a slow but steady trend towards building a proper **European layer of distribution regulation**. Historically, this area was left to member states. However, the process that established EU-wide network codes for transmission is now being replicated for distribution.
- A key milestone was the 2019 Clean Energy Package, which established the **EU DSO Entity**, a legal body representing DSOs at the European level, similar to the ENTSO-E for transmission operators. This entity is now co-drafting new EU-wide network codes on topics like demand response and cybersecurity, which directly impact distribution-level activities.
- This process is complicated by the extreme heterogeneity of European DSOs in terms of size, ownership, unbundling status, and scope of services. Nonetheless, the increasing interconnectedness of the energy system and the cross-border nature of many new challenges are driving the need for greater harmonisation. The recent review of the EU electricity market design, finalised in 2024, further strengthens this trend by putting DSOs on a more equal footing with TSOs in system planning and by setting new EU-wide rules on active consumers, flexibility, and data access. The 2020s are set to be the decade where a distinct European regulatory framework for electricity distribution truly takes shape.

Chapter 6: Regulation of Access, Pricing, and Planning of High-Voltage Transmission in the US

By Joe DeLosa III, Johannes P. Pfeifenberger and Paul L. Joskow

A Complex Regulatory Framework

The regulation of high-voltage electricity transmission in the United States is exceptionally complex, governed by a web of separate but overlapping federal and state authorities. We provide an overview of how transmission investments are priced and recovered and the planning processes that individual transmission owners and regional grid operators use to plan the necessary expansion of the high-voltage transmission grid. We also point out some of the economic inefficiencies that are created by a combination of balkanized regulatory structures and outdated industry planning practices.

The separate, but overlapping, jurisdictional authorities of the U.S. federal regulators and those of individual states, districts, and territories is the central feature of US transmission regulation.

- **Federal Authority (FERC):** The Federal Energy Regulatory Commission (FERC) has jurisdiction over the "transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale". Rates approved by FERC must be "just and reasonable".
- **State Authority (PUCs):** State Public Utility Commissions (PUCs) have jurisdiction over retail electricity services, which includes the local distribution network and the retail cost of transmission service bundled for a utility's "native load" customers. States also control the permitting and siting of new transmission facilities within their borders.

This dual jurisdiction creates inherent tensions, though FERC's 7-factor test is used to distinguish between state-regulated distribution and federally-regulated transmission. Other sovereign powers of states impact the development even of FERC-jurisdictional transmission facilities, including state "Certificate of Public Convenience and Necessity" (CPCN) approvals. FERC's jurisdiction does not extend to all transmission providers; municipal utilities, cooperatives, and federal power marketing agencies are often non-jurisdictional, as is most of the grid in Texas (ERCOT).

The Evolution Towards Transmission Open Access and Wholesale Markets

For much of the 20th century, the electricity system was owned and operated by vertically integrated utilities that planned and built their own generation, transmission, and distribution primarily to serve their own retail customers. To set the framework for wholesale power markets in response to state restructuring efforts of the 1990s, a series of landmark FERC orders overhauled the method of using, selling, and planning transmission facilities in the U.S., creating "open access" to the interstate transmission system.

- **FERC Order 888 (1996):** Requiring public utilities to provide open, non-discriminatory access to their transmission systems for all market participants, ending the ability of incumbent utilities to favor their own generation resources;
- **FERC Order 2000 (1999):** Promoting the voluntary formation of Independent System Operators (ISOs) and Regional Transmission Operators (RTOs), non-profit organizations that operate the transmission grid and manage wholesale power markets, and setting their minimum required characteristics and functions.

FERC Evolving Regional Transmission Policy

FERC continued to further advance transmission reform, responding to shortcomings in previous system planning processes and steadily requiring more open, transparent, and coordinated frameworks to evaluate necessary transmission expansions or enhancements.

- **FERC Order 890 (2007):** Establishing nine principles for transmission planning, including region-wide coordination, early opportunities for open stakeholder and customer engagement, and a method of regionally allocating the costs of resulting transmission projects;
- **FERC Order 1000 (2011):** Requiring transmission providers to participate in a regional transmission planning process to select the more efficient or cost-effective solution to solve identified regional transmission needs, including by removing the federal "right-of-first-refusal" by incumbent utilities, enabling competitive transmission development;
- **FERC Order 1920 (2024):** Requiring development of a long-term transmission plan, and the assessment of potential transmission needs arising across a set of plausible future scenarios. Solutions to the identified long-term needs must be evaluated using (at least) a set of seven specific benefit categories when identifying cost-effectiveness.

Despite these reforms, transmission planning in the US remains highly fragmented and often inefficient. Planning processes are typically siloed, addressing unique drivers of transmission incrementally rather than holistically.

Planning solely for <u>reliability</u> needs accounts for 90–95% of all U.S. transmission investment, with planning for economic and public policy accounting for most of the remainder. This segment includes regional reliability projects (planned by the RTO/ISO) as well as local transmission projects (planned and constructed by the incumbent transmission owner);

- Reliability needs include those driven by generators seeking to interconnect. If new transmission ("network upgrades") are deemed necessary to reliably transmit the interconnecting generator's output to load, most grid operators will allocate the cost of these network upgrades on a pro-rata share to the interconnecting generators that contribute to the need for the upgrade;
- Economic or "market efficiency" needs are often limited to relieving transmission congestion with benefits narrowly quantified through forward-looking market simulations that are highly normalized and do not consider challenging market conditions; that these types of narrowly-defined economic planning processes have not resulted in the approval of many economic or market efficiency transmission projects;
- Public policy needs are oftentimes narrowly defined, with a similarly poor track record, though some regions are now addressing economic and public policy needs more holistically through multi-driver planning;
- Interregional transmission projects serve to enable power transfers and improve reliability by connecting multiple ISO/RTOs and non ISO-planning regions. FERC Orders only require interregional *coordination*, not interregional *planning*, leaving in place several challenges for identifying and making such investments actionable in transmission plans.

The compartmentalization of transmission planning by separately addressing different types of transmission needs yields incremental investments that foreclose more efficient (e.g., larger scale) solutions that could address multiple needs. But this is not the only source of planning inefficiencies. The sequencing of individual planning processes also makes it very difficult to identify cost effective transmission solutions. Local projects that are planned and approved before regional needs are considered can pre-empt more efficient regional solutions that can simultaneously address local needs.

And regional projects approved before interregional needs are studied can pre-empt more efficient interregional solutions that can simultaneously address regional needs.

To account for all transmission needs in the most efficient manner, planning processes will have to move beyond today's siloed, reactive planning processes that respond to each need as they arise, often with local solutions. Instead, efficient regional transmission planning will need to proactively look at both the near-term and long-term transmission needs that arise as system conditions evolve. Through such proactive, holistic planning processes, regions can not only evaluate multiple needs simultaneously; but when evaluating alternative transmission solutions that can address the identified needs, they can also evaluate the extent to which benefits provided (including avoided generation and other transmission costs) differ across alternative solutions. The chosen transmission solutions will be those that address the identified near- and longer-term needs at the highest benefit-cost ratio (or highest net benefits), while also considering long-term uncertainties and non-monetary considerations such as community impacts.

Transmission Cost Allocation and Rate Recovery

The initial step in recovering the costs for any transmission investment is identifying the universe of customers that will be responsible for funding the cost of a specific transmission facility. Precedent requires that the costs borne by different groups of ratepayers for each transmission facility are "roughly commensurate" with the benefits the facility provides to those customers. In light of this standard, FERC and the courts have allowed for significant regional variation in the particular methods of identifying beneficiaries and allocating costs associated with transmission facilities.

The annual costs of regulated transmission facilities are recovered through transmission revenue requirements, determined by FERC using traditional cost-of-service principles. Often, transmission costs are recovered through formula rates, which includes an annual update used to reflect investment placed in service by the utility during the preceding year.

These costs are ultimately recovered from end-use customers through their state-regulated retail electricity bills. While state regulators can participate in the transmission planning process and FERC transmission rate cases as stakeholders and retain authority to decide how transmission costs are recovered from different retail rate classes (e.g., commercial, industrial, residential, etc.), state utility commissions ultimately do not retain the authority to disallow recovery of transmission investment approved by FERC.

Chapter 7: Regulation of Access, Fees, and Investment Planning of Transmission in Great Britain

By David Newbery

Background and Evolution

The regulation of electricity transmission in Great Britain (GB) offers a distinct and insightful case study, shaped by a history of unbundling, the introduction of competitive markets, and an ambitious commitment to decarbonisation. Until the 1990s, the system was vertically integrated and state-owned. Liberalisation led to the legal and ownership separation of competitive generation from the monopoly network businesses.

National Grid became the Transmission System Operator (TSO) for England and Wales, later expanding its role to cover all of GB under the British Electricity Trading and Transmission Arrangements (BETTA) in 2004. A key recent development has been the structural separation of the system operator function from the transmission asset ownership function within the National Grid parent company. In 2019, the Electricity System Operator (ESO) was created as a legally separate entity. Following this, plans were developed to move the ESO into full public ownership as a new Future System Operator (FSO), a transition completed in 2024 with the creation of the National Energy System Operator (NESO). This move was designed to eliminate any potential conflict of interest between the ESO's role in planning and operating the system and the transmission owner's incentive to build assets, and to create a trusted, independent body to guide the system's evolution towards net zero.

Network Regulation: From RPI-X to RIIO

The overarching regulatory framework for transmission in GB has followed the same evolutionary path as for distribution, moving from the initial RPI-X price cap model to the more sophisticated **RIIO (Revenue = Incentives + Innovation + Outputs)** framework from 2013. The RIIO model, applied to transmission, addresses the inherent bias towards capital-intensive solutions that can exist under simpler regulatory models. It does this by focusing on incentivising efficiencies in **Total Expenditure (Totex)**, which is the sum of capital and operating expenditure. This encourages the TSO to make efficient trade-offs between building new assets and using operational measures to manage the system.

The RIIO framework for transmission also includes strong incentives and penalties linked to a wide range of outputs, including reliability, environmental impact, and customer satisfaction. It incorporates specific funding mechanisms for innovation, which are awarded through competitive processes to encourage the development and deployment of new technologies and operating practices. The allowed revenue for the transmission owner is determined through a detailed building-block approach, where the regulator (Ofgem) sets allowances for Totex and determines a fair weighted average cost of capital (WACC) on the Regulatory Asset Value (RAV).

Transmission Charging: A Unique Locational Approach

A distinctive and central feature of the GB regime is its approach to transmission charging, which employs strong **locational signals** to guide investment and dispatch decisions. The charges, known as Transmission

Network Use of System (TNUoS) tariffs, are designed to reflect the cost of using the network in different geographic locations.

- **Generation TNUoS (G-TNUoS):** Generators pay an annual charge (in £ per kilowatt of entry capacity) that varies significantly by zone. Generators in remote areas far from demand centres (e.g., Northern Scotland, with its abundant wind resources) face high positive charges. Conversely, generators located in areas with high demand and limited local generation (e.g., Southern England) face negative charges, meaning they are *paid* to be connected to the grid in that location if they deliver at seasonal peaks. This creates a powerful financial incentive for new generation to locate closer to load centres, which helps to minimise the need for new transmission investment.
- **Load TNUoS (L-TNUoS):** Demand users (via distribution companies) also pay a locationally differentiated tariff. The charges are highest in high-demand areas and lower in areas with surplus generation.

The sum of the generation and load tariff in any given zone is roughly constant, ensuring that the total required revenue is collected. The charges are recalculated annually by the ESO, based on a complex model that estimates the incremental cost of expanding the network to accommodate an additional unit of generation or demand in each zone.

While this system provides strong long-run locational signals, it has faced challenges. The methodology is complex and backward-looking, meaning the tariffs can be slow to adapt to rapid changes in the generation mix. Furthermore, the strong incentives provided by renewable energy support schemes (such as the Renewables Obligation and later Contracts for Difference) have overwhelmed the G-TNUoS signals, over-encouraging wind farm development in remote, high G-TNUoS areas. The combined difficulty of securing consents to expand transmission and the over-encouragement of the "connect and manage" regime (forcing the grid to offer connections despite inadequate capacity) has led to significant congestion on the transmission network, particularly on the boundary between Scotland and England, resulting in high constraint costs that are paid by consumers.

Reforms and the Future of Market Arrangements and Transmission planning

The GB transmission charging regime has been subject to almost continuous review and reform to address these challenges.

- **Project TransmiT (2010):** This major review refined the TNUoS methodology to better reflect the different operating characteristics of intermittent renewables versus conventional power plants.
- **Targeted Charging Review (2019):** This review addressed a significant distortion known as the "embedded benefit". Small generators connected to the distribution network were able to avoid paying generation charges while also receiving a credit for notionally reducing the load on the transmission network. This created a perverse incentive for polluting diesel generators to connect at the distribution level, particularly to participate in the capacity market. The review removed this distortion, saving consumers billions of pounds.
- The Government launched a major **Review of Electricity Market Arrangements (REMA) in 2022**. An initial key proposal was a move to **Locational Marginal Pricing (LMP)**, or nodal pricing, common in the US. Under LMP, the wholesale energy price itself would vary by location, providing real-time signals for efficient dispatch and highlighting the value of relieving congestion. Proponents argue that LMP would eliminate the need for the ESO to make costly constraint payments in the balancing mechanism and would improve overall system efficiency. However, a move to LMP would be a complex and costly transition, requiring a return to a system of central dispatch, which GB abandoned in 2001 and transfer large sums from generators to consumers. LMP and Zonal Price

were abandoned in 2025.

- The transmission requirements to meet GB's net-zero targets are vast and continue to grow. Recognising the need for more holistic and independent planning, the government has legislated for the creation of a new, fully independent **National Energy System Operator**. This new public body will take over all system planning and operational responsibilities from the current system operator (which was legally part of the National Grid group). The NESO will have an enhanced mandate for producing indicative plans for the development of both the electricity and gas networks, with a clear objective of facilitating the net-zero transition in an efficient and coordinated manner. This institutional reform signals a move towards more strategic, centralised planning to guide the significant network investment required in the coming decades.

The Offshore Transmission Regime: A Competitive Model

GB is a world leader in offshore wind, and it has developed an innovative and successful regime for financing and delivering the transmission assets required to connect these offshore wind farms to the onshore grid.

Under the **Offshore Transmission Owner (OFTO)** regime, the wind farm developer builds both the generation and the transmission assets. On completion, the regulator, Ofgem, runs a competitive auction for the ownership, operation and maintenance of the transmission asset. The winning bidder—the OFTO—is the one that offers to own and operate the asset for the lowest annual revenue stream over a fixed period (20-25 years).

This competitive process has been highly effective in driving down the cost of offshore transmission. The OFTO model provides a long-term, index-linked revenue stream, which attracts low-cost capital from infrastructure investors. This contrasts with the financing of onshore transmission, which is done by the incumbent transmission owner under the RIIO price control. The long-term contracts offered to OFTOs also provide a potential model for how to provide long-term certainty for onshore transmission connections, which could strengthen forward-looking locational signals for new onshore generation. Incumbents, who face no location decisions, could continue to face the traditional charges.

In conclusion, the regulation of transmission in GB is characterised by a sophisticated incentive framework (RIIO), a unique system of locational pricing (TNUoS), and a world-leading competitive model for offshore transmission (OFTOs). While the system has successfully driven investment and performance improvements, it faces ongoing challenges in managing congestion and adapting its charging and market arrangements to a renewables-dominated future. The creation of an independent National Energy System Operator and the ongoing review of market arrangements signal a continued commitment to evolving the regulatory framework to meet the demands of the net zero transition.

Chapter 8: The Regulatory Landscape and Investment Planning for Transmission in the EU

By Paul Nillesen, Otto Jager and Joost Ornée

The European Transmission Landscape and its Transformation

The European electricity transmission system is a critical enabler of the energy transition, connecting large-scale renewable generation with demand centres across the continent. The landscape is comprised of more than 30 Transmission System Operators (TSOs), which are predominantly organised along national boundaries. While some countries, like Germany, have multiple TSOs, others have a single national operator. State ownership remains significant, reflecting the view that electricity transmission is an essential service critical for national security and economic stability. Many TSOs are also involved in international operations and offshore grid development.

Two profound societal trends are reshaping the European transmission landscape:

1. **The Energy Transition:** The rapid buildout of renewable energy sources (RES), particularly wind and solar, and the phasing out of conventional thermal power plants are fundamentally altering power flows. RES are often decentralised, intermittent, and located far from traditional generation centres. This shift necessitates a massive expansion and reinforcement of the grid, including a significant increase in cross-border interconnection capacity to share renewable energy efficiently and enhance system stability. The push for electrification in transport and heating is further projected to increase overall electricity demand, adding to the pressure on the grid.
2. **Declining Public Acceptance:** TSOs face growing public opposition to new infrastructure projects, a phenomenon often referred to as "NIMBYism" (Not In My Backyard). Concerns about visual impact, environmental effects, and property values lead to lengthy and uncertain permitting processes, which are a major barrier to the timely delivery of necessary grid upgrades. This has, in some cases, pushed TSOs to prioritise more expensive offshore or underground cable projects over onshore overhead lines.

These trends mean that existing European transmission grids are increasingly strained. They are less capable of handling peak power flows, leading to rising congestion costs, which are managed through expensive redispatch and curtailment measures. For example, in the Netherlands, the cost of managing grid balance increased fifteen-fold between 2019 and 2022.

Seven Key Challenges for European TSOs

European TSOs are confronting a set of simultaneous and interconnected challenges that are unique in their scale and complexity.

1. **Supply Chain Constraints:** The global boom in grid expansion has led to increasing scarcity and rising costs of critical components, such as high-voltage cables and transformers, as well as specialised engineering and construction capacity.
2. **Extended Realisation Time Frames:** The combination of lengthy planning and licensing procedures and local opposition means that the timeline from planning to commissioning a new transmission

line can be a decade or more, significantly longer than for building a new wind or solar farm.

3. **Financing Constraints:** The required grid investments are vast, running into the multi-billions of euros. While state ownership can help, attracting sufficient capital at a reasonable cost remains a key challenge, particularly as project costs rise due to inflation and supply shortages.
4. **Outdated Regulatory Frameworks:** Many existing regulatory frameworks were designed with a focus on cost efficiency for mature networks. They are often backward-looking and not well-suited to incentivising the massive, proactive, and innovative investments now required. The focus is only recently beginning to shift towards security of supply and facilitating the energy transition.
5. **Intermittency and Lack of Inertia:** The replacement of large, rotating synchronous generators (from thermal and nuclear plants) with inverter-based renewable sources reduces the physical inertia in the system. Inertia acts as a shock absorber, helping to maintain grid stability. Its decline makes managing the system balance more challenging.
6. **Operational and System Complexity:** Managing a grid with a high share of intermittent renewables and complex, multi-directional power flows is far more complex than operating a traditional system. TSOs need to invest in and adopt new digital tools, data analytics, and artificial intelligence to manage this complexity efficiently.
7. **Planning Uncertainty:** TSOs need to plan for a future with high uncertainty regarding the exact location and timing of new generation and demand, as well as the emergence of new technologies like large-scale energy storage and hydrogen.

The European Regulatory Framework for Transmission

TSO regulation in Europe is based on a dual system of EU directives and national regulations. The EU's Third Energy Package (2009) and the subsequent Clean Energy for All Europeans package (2019) have established a framework for an integrated internal energy market. This includes rules on the separation (unbundling) of TSOs from competitive activities, requirements for fair and equal access to the grid, and the establishment of independent National Regulatory Authorities (NRAs).

At the national level, the most common form of tariff regulation is a **revenue-cap approach**. The NRA sets a cap on the total revenue the TSO can earn over a regulatory period (typically 3-5 years). This cap is usually based on a forecast of efficient costs. This approach provides an incentive for the TSO to keep its costs below the cap. Many frameworks also include specific incentives for performance in areas like reliability or innovation. However, these frameworks face challenges in the current environment. A backward-looking approach, where the revenue cap is based on past costs, is poorly suited to a period of rapid investment growth. There is a need for more forward-looking approaches that can provide timely cost recovery for new investments.

Cross-Border Transmission and Market Integration

Integrating national markets and increasing cross-border transmission capacity are central to the EU's energy policy.

- **Interconnection Targets:** The EU has set a target for each member state to have electricity interconnection capacity equal to at least 15% of its installed generation capacity by 2030.
- **Cross-Border Cost Allocation (CBCA):** The CBCA regulation provides a framework for TSOs to cooperate on and agree to the cost allocation for cross-border projects. The Agency for the Cooperation of Energy Regulators (ACER) provides guidelines and can make decisions if TSOs cannot agree.
- **Market Coupling:** European electricity markets are "coupled" to ensure that power flows efficiently from lower-price to higher-price areas. **Flow-Based Market Coupling (FBMC)**, used in Central Western Europe, is a sophisticated method that optimises cross-border exchanges based on a detailed model of the entire regional grid, rather than just bilateral capacity on individual interconnectors.
- **The 70% Rule:** The Clean Energy Package requires that a minimum of 70% of the capacity on interconnectors must be made available for cross-zonal trade. This is designed to reduce the practice of TSOs limiting cross-border capacity for internal grid management purposes, thereby promoting a more integrated market. Many countries are struggling to meet this target.

A key ongoing debate in Europe is the choice between **zonal and nodal pricing**. The current zonal model, where prices are uniform within large zones (typically national borders), can be inefficient. It does not provide locational signals to guide generation and large loads to areas with less grid congestion. A move to a nodal pricing model, as used in the US, would create more granular, location-specific prices, which could alleviate transmission bottlenecks and incentivise more efficient siting decisions. However, the European Commission has so far ruled out a shift to nodal pricing, though the debate continues.

In conclusion, European TSOs are at the heart of the energy transition, facing unprecedented challenges in expanding and modernising the grid. While the EU has established a sophisticated regulatory framework to promote an integrated market, this framework must continue to evolve. Regulators and policymakers need to urgently address supply chain constraints, streamline planning and permitting, adapt regulatory models to encourage proactive investment, and enhance cross-border cooperation to build the resilient, continent-wide grid required for a net zero future.

Chapter 9: The Regulation of Electricity Networks in Australia’s National Electricity Market

By Paul Simshauser

Background and Institutional Design

Australia's National Electricity Market (NEM), which covers the five eastern and south-eastern states, was formed in the 1990s as part of a worldwide wave of microeconomic reform. The reform process, largely based on the British template, transformed the industry from one dominated by state-owned, vertically integrated monopolies into a restructured market with competitive generation and retail sectors and regulated monopoly network businesses.

A key strength of the Australian model lies in its **institutional design**, which segregates the functions of policymaking, rulemaking, regulation, and market operations into four distinct bodies:

1. **Energy and Climate Change Ministerial Council:** Comprised of the energy ministers from each participating state and the Commonwealth government, this body is responsible for overall energy policymaking.
2. **Australian Energy Market Commission (AEMC):** The AEMC is the independent rulemaking body. It operates through an open, transparent process where any stakeholder can propose a change to the National Electricity Rules. The AEMC assesses proposals against the National Electricity Objective, which is to promote efficient investment and operation in the long-term interests of consumers.
3. **Australian Energy Regulator (AER):** The AER is the economic regulator for the NEM's transmission and distribution networks and enforces the rules set by the AEMC.
4. **Australian Energy Market Operator (AEMO):** AEMO is the independent market and system operator, responsible for central dispatch of generation and managing the operation of the wholesale market and the security of the power system.

This separation of powers provides a stable and predictable environment, which has given confidence to institutional investors. The rules governing the market and its regulation are highly prescriptive, which limits the potential for capricious regulatory action but can also reduce flexibility to adapt to rapidly changing circumstances.

The Form of Economic Regulation

The economic regulation of Australia's electricity networks is based on an incentives-based **revenue cap** model, similar to the British RPI-X framework. The AER conducts regulatory determinations, typically for a five-year period, for each network utility.

The process follows a "propose and respond" model. The network utility submits a detailed Revenue Proposal outlining its forecast operating expenditure (Opex) and capital expenditure (Capex). The AER then scrutinises this proposal through a public consultation process, involving consumer advocates and a regulator-sponsored Challenge Panel, before issuing a final determination on the allowed revenue.

The annual revenue requirement is determined using a standard **building-block approach**, which includes allowances for Opex, a return of capital (depreciation), and a return on capital applied to the Regulatory Asset Base (RAB). A historically contentious element has been the determination of the weighted average cost of capital (WACC). Following years of litigation, the framework was changed to give the AER a more unilateral role in setting the WACC, removing a merits review process.

User Charges, Investment, and Access

- **Customer Charges:** The costs of the shared transmission and distribution (T&D) networks are recovered from end-use consumers. Generators pay only for their "shallow" connection assets. For a typical household, the combined T&D network charge makes up around 36% of the final electricity bill and is structured as a two-part tariff with a fixed daily charge and a variable charge per kWh.
- **Investment in the Shared Network:** All significant new network investments (above AUD 7 million) must pass a **Regulatory Investment Test for Transmission (RIT-T)** or its distribution equivalent (RIT-D). The RIT-T is a formal, public cost-benefit analysis designed to identify the investment option that maximises the net economic benefit to the market. The test considers non-network solutions (like demand response or local generation) as alternatives to traditional network augmentation. While sound in principle, the RIT-T process has been criticised for being slow and cumbersome, and for excluding important benefits such as the value of CO_2 emissions reductions.
- **The Integrated System Plan (ISP):** Recognising the limitations of the project-by-project RIT-T approach for long-term planning, a second pathway for transmission investment has emerged through the ISP. The ISP is a biennial, whole-of-system plan developed by the market operator, AEMO. It identifies an optimal development path for the NEM, including priority transmission projects needed to facilitate the energy transition. For these "actionable" ISP projects, the RIT-T process is streamlined; its role is not to question whether the project should proceed, but to identify the most efficient option for delivering it.
- **State-led Initiatives and Renewable Energy Zones (REZ):** The perceived rigidity of the national regulatory framework has led some state governments to create their own legislative frameworks to fast-track transmission investments for "transformational" projects or to develop REZs. Queensland has pursued a novel "merchant" model for some REZs, where an anchor renewable generator underwrites the cost of a new radial transmission line, which then sits outside the regulated asset base.
- **Network Access and Locational Signals:** The NEM operates a strict **non-firm, open access** regime. No generator has a guaranteed right to export power. Locational signals for new generation are provided through a combination of five zonal wholesale spot prices and, more importantly, **Marginal Loss Factors (MLFs)**. An MLF is a coefficient applied to the spot price at each of the NEM's ~1,400 connection points to reflect the marginal cost of transmission losses. A generator in a remote area with high losses will have an MLF below 1.0 (receiving less than the regional price), while one in a location that reduces system losses will have an MLF above 1.0 (receiving a premium). This creates powerful and granular locational price signals. Crucially, under bilateral contracts (PPAs), the generator typically bears the full risk of both congestion and adverse changes in its MLF, strongly incentivising prudent locational decisions.

Performance of Regulation: A Tale of Two Decades

The performance of network regulation in Australia has been a story of two distinct periods.

- **The 2007–2015 "Gold-Plating" Episode:** This period was marked by a massive over-investment in network capacity. The primary driver was a policy error by state governments in NSW and Queensland. Following a series of blackouts, they tightened network reliability standards from a probabilistic to a deterministic approach, mandating a huge build-out of capacity. This coincided with the Global Financial Crisis, during which the formulaic nature of the WACC determination forced the AER to lock in historically high rates of return for five-year periods. The combination of soaring investment, a high allowed WACC, and, unexpectedly, the first sustained contraction in grid-supplied electricity demand (due to rooftop solar and energy efficiency) led to a dramatic surge in network tariffs. For example, in Queensland, real residential tariffs increased by 8.3% per annum during this period.

- **The Post-2015 Correction:** The regulatory framework proved capable of correcting this trajectory. State governments abandoned the overly stringent reliability standards. The AER took a much harder line on Opex and Capex allowances in subsequent determinations and capitalised on the low-interest-rate environment to push down the allowed WACC. These actions successfully moderated the growth in network tariffs, and networks are now seen as a relatively stable component of the customer bill.

In conclusion, the Australian regulatory framework for electricity networks has significant strengths, particularly its independent and transparent institutional design, which provides confidence to investors. Its use of sharp locational signals and a "first ready, first served" connection process has also helped avoid the connection queues seen in other markets. However, its highly prescriptive nature has created weaknesses, limiting the regulator's flexibility and leading to state governments increasingly bypassing the national framework to pursue their own decarbonisation objectives. The experience of the gold-plating era provides a salutary lesson for all jurisdictions on the dangers of policy error and the importance of allowing regulatory frameworks to adapt to unforeseen economic conditions.

Chapter 10: Retail Rate Design in the US: Time-Varying Rates for Residential Customers

By Ahmad Faruqui and Ziyi Tang

The Long Evolution of Time-Varying Rates

For most of the 20th century, residential electricity tariffs in the United States were simple volumetric rate designs, often in the form of declining block rates where the price per kilowatt-hour (kWh) decreased with higher consumption. This reflected an era of declining average costs for electricity production.

The energy crises of the 1970s marked a turning point. With soaring energy costs, conservation became a national priority, catalysed by the Public Utility Regulatory Policies Act (PURPA) of 1978. This spurred the first serious exploration of **Time-of-Use (TOU) pricing**. The theory was simple and compelling: the cost of generating electricity varies significantly throughout the day and year. It is much more expensive to meet demand during peak hours, when less efficient "peaker" plants must be run, than during off-peak hours. A flat volumetric rate masks this reality, leading to inefficient consumption patterns. TOU rates, by charging higher prices during on-peak periods and lower prices during off-peak periods, aim to provide customers with more cost-reflective price signals, encouraging them to shift consumption to lower-cost periods.

This initial interest led to a **first wave** of 16 federally-funded TOU pilot projects in the late 1970s and early 1980s. These pilots provided early evidence that residential customers do respond to time-varying prices by reducing their on-peak usage. However, widespread adoption was stymied by two major barriers: the lack of interval metering (smart meters) and consistent opposition from consumer advocates who favoured the simplicity of flat rates.

Interest in TOU rates languished until the **third wave** was triggered by the California energy crisis of 2000-2001. This crisis starkly demonstrated the high cost of peak demand and renewed interest in using pricing to manage load. A new generation of pilots was launched, not just for TOU rates but also for more advanced forms of **dynamic pricing**, such as:

- **Critical-Peak Pricing (CPP):** This involves a standard TOU rate structure, but on a limited number of "critical" days per year (e.g., the hottest summer afternoons), the on-peak price is raised substantially to reflect extremely high system costs or reliability concerns.
- **Real-Time Pricing (RTP):** Here, the retail price varies hourly to reflect the actual price in the wholesale market.

These pilots, most notably a large statewide pilot in California in 2003-2004, were game-changers. They were more scientifically rigorous than the first-wave pilots and often included "enabling technologies" like smart thermostats and in-home displays. The results were clear and consistent: customers reduce their peak-period energy use in response to time-varying prices, and the higher the peak-to-off-peak price ratio, the larger the response. Furthermore, enabling technologies were shown to significantly enhance this price responsiveness. This body of evidence provided the justification for widespread investment in Advanced Metering Infrastructure (AMI), or smart meters.

The Current State: The Slow Rollout of Smart Rates

We are now in the **fourth wave**, characterised by the large-scale rollout of both smart meters and, more slowly, time-varying rates (TVR). As of 2022, 73% of US households have a smart meter. However, only 9.4% are on a TOU rate. This gap between technological capability and rate reform highlights the persistent barriers to implementation. These include:

- **Stakeholder Inertia:** Regulators, utilities, and consumer advocates remain cautious, often fearing a customer backlash or a failure to realize the expected benefits.
- **Customer Dissatisfaction and Bill Impacts:** Moving from flat rates to TVR inevitably creates "winners" and "losers". Customers whose consumption is concentrated in peak periods will see their bills increase, at least initially. This can lead to dissatisfaction if the transition is not managed carefully.
- **Equity Concerns:** There are valid concerns about the impact on vulnerable customers, such as low-income households, the elderly, or those with medical needs, who may have less flexibility to shift their consumption.

Despite these barriers, the trend is towards greater adoption of TVR. The number of households on TOU rates more than doubled between 2018 and 2022, and if this trend continues, 25-35% of households could be on TOU rates by 2030. A growing number of utilities, particularly in states like California, Colorado, and Michigan, are moving to make TOU rates the **default option** for residential customers, while allowing them to opt-out to a flat rate.

Strategies for a Successful Transition

Experience from four decades of deploying TVR has yielded several key lessons for utilities and regulators seeking to modernise their rate designs. A successful transition typically involves a carefully planned, nine-step pathway:

1. **Select Rate Designs:** Offer a portfolio of rate options along an "efficient pricing frontier" that allows customers to choose their preferred trade-off between risk (bill volatility) and reward (potential bill savings). Options can range from guaranteed bills to TOU, CPP, and RTP.
2. **Analyse Bill Impacts (Static):** Before any rollout, conduct a thorough analysis to understand how many customers will see their bills increase or decrease under the new rates, assuming no change in behaviour.
3. **Understand "Losers":** Identify the characteristics of customers who will face adverse bill impacts to design targeted mitigation strategies.
4. **Analyse Bill Impacts (Dynamic):** Re-run the analysis, modelling the likely behavioural response of customers to the new price signals, which will show how bill impacts are mitigated as customers shift their load.
5. **Consider Remedies:** If significant adverse impacts remain, implement remedies such as gradual phase-ins of the new rates, temporary bill protection, or specific financial assistance for vulnerable customers.
6. **Conduct Focus Groups:** Engage with customers to gauge acceptance and refine communication strategies.
7. **Run a Scientific Pilot:** If necessary, run a well-designed pilot to measure customer response in the local context.
8. **Determine Rollout Strategy:** Decide whether the new rates will be opt-in, opt-out (default), or mandatory. The default approach is increasingly seen as the most effective for achieving broad participation.

9. **Track and Modify:** After rollout, continuously track customer response and feedback, and be prepared to modify rate designs as needed.

The Future: The Fifth Wave and the Net Zero Transition

We are now entering a **fifth wave** of rate design, driven by the imperatives of the net zero transition. The widespread deployment of new technologies is fundamentally changing the relationship between customers and the grid.

- **Electrification:** The growth of electric vehicles (EVs) and heat pumps will significantly increase residential electricity demand and create new, large, and flexible loads.
- **Distributed Generation:** The proliferation of rooftop solar PV panels, often paired with battery storage, is transforming customers into "prosumers" who both consume and produce energy.

These developments make cost-reflective retail pricing more crucial than ever. The "duck curve" phenomenon, already common in California, where abundant midday solar generation pushes net demand to very low levels, only for it to ramp up steeply in the evening as the sun sets, requires price signals to manage this new system dynamic. TVR are an indispensable tool to encourage customers to charge their EVs or run their appliances during periods of low-cost, abundant renewable energy.

The future of retail pricing is likely to move towards even more dynamic and sophisticated models. The concept of **transactive energy**, where customers or their smart devices can interact directly with the market, is gaining traction. In one vision, customers might subscribe to a "baseline" load profile and then buy or sell deviations from that baseline in real-time, capturing value from their flexibility.

For decades, TVR was an exotic concept. The convergence of smart meter deployment, the rise of customer-sited technologies like solar and EVs, and the urgent need to manage a grid with high levels of renewables is finally moving it from the periphery to the mainstream of electricity pricing.

Chapter 11: Economics of Energy Efficiency

By Kenneth Gillingham and Erica Myers

The Energy Efficiency Paradox

Energy efficiency is widely seen as a cornerstone of any low-cost strategy to mitigate climate change. Investments in more efficient appliances, vehicles, and buildings can reduce energy demand, lower carbon emissions, and, it is often argued, save consumers money through lower energy bills. Indeed, many analyses suggest that there are numerous "negative cost" abatement opportunities, where the present value of the future energy savings exceeds the upfront investment cost.

This raises a central question in the economics of energy efficiency: if these investments pay for themselves, why are consumers not undertaking them voluntarily? This phenomenon is known as the **"energy efficiency paradox"** or the "energy efficiency gap". Understanding the reasons behind this gap is crucial for designing effective public policy.

Explaining the Gap: Competing Interpretations and Underlying Causes

A vibrant body of research has explored the energy efficiency paradox, questioning whether the gap between seemingly optimal and actual investment reflects real inefficiency or an artifact of measurement. Some explanations suggest the paradox is overstated, while others imply a genuine shortfall in privately optimal investment. A further set of considerations for underinvestment in efficiency—environmental externalities—are conceptually distinct from the efficiency gap itself.

1. **Apparent Gaps: When the Paradox May Be Overstated**
   - Analyst Error and Hidden Costs: The paradox may partly reflect analysts' mismeasurement of costs or savings. Engineering models used by policymakers often overstate realized energy savings, and analyses sometimes neglect "hidden costs" such as search and installation time or reduced non-energy product quality (e.g., early LED light tone). When these factors are recognized, many investments that appeared cost-effective on paper may not be in practice.
2. **True Gaps: When Consumers Underinvest Relative to Their Own Best Interest**
   - Information Failures: Consumers may lack the information needed to make optimal choices or face asymmetric incentives. For example, in the rental market, a landlord who does not pay the utility bills has little reason to invest in efficiency, while tenants may lack information or bargaining power to induce such investment.
   - Behavioural Anomalies: Insights from behavioural economics indicate that consumers may systematically deviate from rational decision-making even when information is available.
     - Limited Attention: Consumers may overlook the efficiency attribute, focusing instead on price or brand.
     - Biased Beliefs: They may underestimate future energy prices or their own usage.
     - Loss Aversion: They may overweight the risk of savings not materialising relative to the potential gain.
3. **A Separate Issue: Socially Suboptimal Investment Due to Externalities**
   - Environmental Externalities: The price of energy typically fails to reflect the full social cost of consumption, including pollution and greenhouse gas emissions. Even if consumers make decisions that are privately optimal, society will still under-invest in efficiency from a welfare perspective. This is sometimes considered to be part of the "energy efficiency gap", but it really

is a distinct market failure that justifies corrective policies such as carbon pricing.

If the gap reflects genuine market or behavioural failures—cases where consumers underinvest relative to their own best interest—then there is a strong rationale for policy intervention to improve private and social welfare. Externalities, while conceptually distinct from the efficiency gap, provide an additional and independent justification for policy action.Evaluating Energy Efficiency Policies

A wide range of policies are used to promote energy efficiency. Recent economic research has provided valuable evidence on their impacts and cost-effectiveness.

- **Residential Retrofit and Weatherization Programmes:** These programmes, which often provide free or heavily subsidised retrofits for low-income households, have been a major focus of policy. Rigorous evaluations, such as studies of the US Weatherization Assistance Program (WAP), have consistently found that the **realised energy savings are significantly lower than the engineering projections**. This "performance wedge" appears to be driven primarily by modelling bias (the engineering models are systematically optimistic) and issues with the **quality of contractor work**. There is evidence that contractors may shirk on quality when their work is not easily monitored. However, research also shows that programme performance can be improved. Using data-driven methods to **target retrofits** to households where the predicted savings are highest can substantially increase cost-effectiveness. Furthermore, providing **performance-based incentives** to contractors can improve the quality of their work and increase realised energy savings.
- **Rebate Programmes:** Providing rebates for the purchase of efficient appliances is a very common policy. Evidence suggests these programmes can be hampered by a high degree of **"free-ridership",** where the rebate is claimed by consumers who would have purchased the efficient product even without the incentive. This reduces the "additionality" and cost-effectiveness of the programme. There is also evidence that consumers may use the rebate to buy a larger or more feature-rich model, which can partially offset the energy savings from the improved efficiency.
- **Information and Labelling Policies:** To address information failures, governments implement labelling schemes like the EnergyGuide in the US or the A-G scale in Europe. The evidence on the effectiveness of simply providing more information is mixed. Some studies find little effect on purchasing decisions, suggesting that consumers may be inattentive. However, there is stronger evidence for the effectiveness of **mandatory disclosure** policies in housing markets. Requiring sellers to disclose a home's energy performance can lead to the value of energy efficiency being more fully capitalised into house prices and can stimulate greater investment in energy-saving retrofits. Labelling programmes for the most-efficient products, like EnergyStar, appear to increase demand for certified products, though they can be an imperfect guide for consumers as the single threshold provides coarse information.
- **Energy Efficiency Standards:** Minimum efficiency standards are a powerful, if blunt, policy tool. They force manufacturers to remove the least efficient products from the market. Their economic efficiency depends crucially on the extent to which consumers undervalue energy efficiency. If consumers are fully rational and attentive, a standard can be inefficient, forcing some consumers to buy more efficiency than they would choose. However, if consumers are inattentive, a standard can correct this market failure and improve welfare. The evidence from the vehicle market is mixed, but suggests there may be some degree of consumer undervaluation, providing a potential justification for fuel economy standards.

In conclusion, the economics of energy efficiency is a complex field where there are no simple answers. The "energy efficiency gap" is not a single problem but a collection of different issues, including hidden costs, market failures, and behavioural biases. While many programmes have been found to deliver lower savings than projected, this does not mean that energy efficiency policy is ineffective. Rather, it highlights the critical importance of careful programme design, rigorous ex-post evaluation, and the use of data-driven targeting and incentives to improve the cost-effectiveness of these essential tools for decarbonisation.

Part II: Regulation on the Path to Net Zero

Chapter 12: The Grid of the Future and What Regulators Need to Know About It

By Janusz Bialek and Mark O'Malley

A Fundamental Shift in Power System Physics

The transition to a decarbonised electricity system powered by high levels of intermittent renewables like wind and solar represents the most significant change in power grids since their inception. This transformation is not just about changing the fuel source; it is a fundamental shift in the underlying physics and technical characteristics of the grid. For economic regulators, understanding this shift is essential for designing frameworks that can ensure a reliable and affordable grid of the future.

The core of this technical change is the replacement of traditional **Synchronous Machines (SMs)** with **Inverter-Based Resources (IBRs)**.

- **Synchronous Machines (SMs):** These are the large, rotating generators found in conventional thermal, nuclear, and hydro power plants. Their behaviour is governed by the laws of physics. The massive rotating mass of these machines provides **inertia**, which acts as a physical shock absorber for the grid. When a large power plant suddenly trips offline, this stored kinetic energy is automatically released, slowing the rate of frequency decline and giving other power plants time to respond and restore balance. All SMs on an interconnected grid rotate in perfect synchronism, creating a stable, common grid frequency (50 Hz or 60 Hz). They also inherently provide services like voltage support and produce large fault currents that are crucial for protection systems to operate correctly.
- **Inverter-Based Resources (IBRs):** Wind turbines, solar PV panels, and battery storage systems do not connect directly to the alternating current (AC) grid. They produce or store direct current (DC) power, which must be converted to AC using a power electronic device called an **inverter**. The behaviour of an IBR is therefore not determined by physics, but by the **software and control algorithms** programmed into its inverter.

This shift from physics to software has profound consequences. IBRs are fast and highly controllable, offering a degree of flexibility that SMs do not possess. However, they lack the inherent robustness of SMs. They have no physical inertia, and their response to grid disturbances depends entirely on how they are programmed.

The Inverter Challenge: New System Needs

As the penetration of IBRs increases and the number of SMs on the system declines, the grid loses its traditional sources of stability. This creates a set of new system needs that were previously provided almost for free by the physical characteristics of SMs. Regulators must ensure that markets and regulatory frameworks are designed to procure these essential services from alternative sources.

- **Loss of Inertia and Frequency Control:** With less inertia, the grid becomes more fragile. A sudden loss of generation will cause the frequency to drop much more rapidly (a higher Rate of Change of Frequency, or RoCoF). This can be dangerous, as it can trigger protective relays to disconnect parts of the grid, potentially leading to cascading failures and widespread blackouts, as seen in major disturbances in South Australia (2016) and Great Britain (2019). While IBRs can be programmed to respond very quickly to frequency deviations (a service known as "fast frequency response"), this is not the same as the instantaneous, automatic inertial response from an SM.
- **Reduced System Strength and Voltage Support:** SMs provide "grid strength", creating a stiff and stable voltage waveform across the network. Most current IBRs are of a "grid-following" (GFL) type; they rely on detecting a strong grid signal to synchronise their output. As SMs are replaced by IBRs, the grid becomes "weaker", which can cause stability problems for the GFL inverters themselves, particularly in remote areas.
- **Changes in Fault Current:** IBRs cannot produce the large fault currents that SMs do, as this would damage their power electronics. This poses a major challenge for traditional grid protection systems, which are designed to detect these large currents to identify and isolate faults like short circuits.

Solutions and Future Directions

Addressing the inverter challenge requires a combination of new technologies, new services, and a fundamental re-engineering of how the grid is operated.

- **Grid-Forming Inverters (GFMs):** A new class of inverters, known as "grid-forming" inverters, offers a promising solution. Unlike grid-following inverters, GFMs can be programmed to act like an SM, actively creating their own voltage and frequency reference. They can operate in "islanded" mode (e.g., in a microgrid) and can provide services like inertia and system strength that are lost when SMs retire. While still a developing technology for large-scale grids, GFMs, particularly when paired with battery storage, are expected to play a crucial role in ensuring stability in a 100% IBR system.
- **New Ancillary Services:** System operators around the world are designing and procuring a new suite of ancillary services to meet the needs of an IBR-dominated grid. These include fast frequency response, synthetic inertia, and various forms of voltage control and damping services. Regulators must approve the market mechanisms and compensation for these new services.
- **Synchronous Condensers:** An interim solution is to install synchronous condensers. These are essentially SMs that are not connected to a turbine; they consume a small amount of power to spin and provide inertia and other stability services without generating energy. While effective, this can be an expensive solution compared to programming IBRs to provide the same services.

The transition to an IBR-dominated grid is a journey into uncharted territory. It presents many technical challenges that are the subject of intensive global research, notably through organisations like the Global Power System Transformation (G-PST) Consortium. For regulators, the key takeaway is that the grid of the future is not just a cleaner version of the grid of the past. It is a fundamentally different system with new stability challenges and new service requirements. Regulation must evolve to recognise these new technical realities, creating market structures and incentives that ensure the procurement of the full range of services needed to maintain a reliable and secure power supply on the path to net zero.

Chapter 13: Decarbonising the US Electricity Grid: Policy and Regulatory Frameworks and Challenges

By Judy W. Chang and Henry Lee

A Patchwork of Policies

The decarbonisation of the US electric power sector is being driven by a complex and often uncoordinated mix of federal and state policies, rather than a single, overarching national mandate. The Biden administration set a goal of 100% carbon-pollution-free electricity by 2035, but this was an executive target, not a federal law. It has been repudiated by the Trump Administration , leaving the U.S with a patchwork of financial incentives, federal agency regulations, and a diverse set of initiatives adopted by about 20 individual states. This structure creates significant regulatory challenges and inconsistencies across the country.

Key Federal Initiatives

At the federal level, two recent pieces of legislation catalyzed a spike in clean energy investment:

- **The Inflation Reduction Act (IRA) of 2022:** The IRA was the most significant climate legislation in US history. It provided hundreds of billions of dollars in long-term tax credits, grants, and other subsidies for a wide range of clean energy technologies. These included production and investment tax credits for wind, solar, nuclear, and energy storage; subsidies for clean hydrogen; and incentives for electric vehicles (EVs), EV charging infrastructure, and the electrification of buildings with heat pumps. A key innovation of the IRA is "direct pay", which allows tax-exempt entities like municipal utilities and cooperatives to receive the value of the tax credits as a direct cash payment, greatly expanding their ability to invest in clean energy. Many, but not all of these incentives were phased out under the Big Beautiful bill adopted in 2025.
- **The Bipartisan Infrastructure Law (BIL) of 2021:** The BIL provided substantial direct federal funding for modernising the nation's infrastructure, including the electricity grid. It included funding for transmission expansion, grid resilience, and innovation partnerships, as well as support for technologies like clean hydrogen and carbon capture.

In addition to this legislation, federal regulatory agencies are playing a crucial role. The **Federal Energy Regulatory Commission (FERC)** has issued rules aimed at streamlining the interconnection process for new generators and improving transmission planning and cost allocation to support the rapid growth of renewables. The **Environmental Protection Agency (EPA)** has issued new standards for vehicle mileage and power plant emissions, designed to accelerate the transition to EVs and cleaner generation. However, many of these federal initiatives are politically contentious and subject to legal challenges.

State-Level Policies

Complementing the federal efforts is a diverse array of policies adopted at the state level. While many states have set aggressive decarbonisation targets, the mechanisms and legal force of these commitments vary widely.

- **Renewable and Clean Energy Standards:** About 30 states have Renewable Portfolio Standards (RPS) or Clean Energy Standards (CES) that mandate a certain percentage of electricity be generated from clean sources by a specific date. These standards create a market for Renewable Energy Credits (RECs), which load-serving entities must procure to demonstrate compliance.
- **State-Sponsored Procurement:** As the cost of renewables has fallen, many states have moved beyond simple REC markets to more direct procurement mechanisms. State agencies or regulated utilities conduct competitive solicitations for large-scale renewable projects, particularly offshore wind. The selected projects are awarded long-term **Power Purchase Agreements (PPAs)**. This approach provides revenue certainty for developers, which is crucial for financing large capital-intensive projects. The costs of these PPAs, to the extent they are above the wholesale market price, are passed on to retail customers.
- **Distributed Energy and Electrification:** States also have a wide range of policies to support behind-the-meter resources, such as subsidies for rooftop solar installations, and to promote electrification through incentives for EVs and heat pumps.

A major challenge is that more than half the states have not adopted significant decarbonisation policies, and many are actively hostile to them. This creates significant conflict within the multi-state Regional Transmission Operators (RTOs), whose stakeholder-based governance structures make it difficult to adopt policies that support the decarbonisation goals of some member states when other member states are opposed.

Regulatory Challenges in a Decarbonising Grid

The massive influx of intermittent renewable energy and the electrification of new sectors are creating unprecedented challenges for the electricity grid and the regulatory frameworks that govern it.

- **Resource Adequacy:** The traditional concept of resource adequacy—ensuring there is enough generating capacity to meet peak demand—is becoming much more complex. The contribution of intermittent wind and solar resources to reliability must be assessed probabilistically (using metrics like Effective Load Carrying Capability, or ELCC). The increasing frequency of extreme weather events also adds to the challenge. Regional Transmission Organizations (RTOs) and state regulators are grappling with how to redesign capacity markets and resource planning processes to ensure reliability in a system dominated by renewables and storage.
- **The Transmission Bottleneck:** Perhaps the biggest single barrier to decarbonisation is the inability to build new transmission infrastructure at the pace and scale required. The best renewable resources are often far from demand centres, and the existing grid lacks the capacity to deliver this power. Building new interstate transmission is notoriously difficult due to a "patchwork" of planning processes, disputes over how to allocate the costs, and a litigious siting and permitting process that can take a decade or more. Without major reforms to transmission planning, cost allocation, and permitting, the US will not be able to build the grid needed to meet its clean energy goals.
- **Modernising the Distribution System:** At the local level, the distribution grid must be transformed from a passive delivery network into a "smart" platform that can manage two-way power flows from millions of distributed energy resources (DERs) like rooftop solar, batteries, and EVs. This requires

significant investment in grid modernization, as well as reforms to retail rate design to provide customers with price signals that encourage them to use their flexible resources in a way that benefits the grid.

In conclusion, the US is pursuing decarbonisation through a fragmented and complex policy landscape. While recent federal legislation has provided powerful financial incentives for clean energy, the underlying regulatory frameworks for planning and operating the grid are struggling to keep pace with the scale of the transformation required. Overcoming the challenges of resource adequacy, transmission expansion, and distribution grid modernization will require greater coordination between federal and state authorities, a willingness to reform long-standing regulatory structures, and the design and development of a national transmission plan to efficiently utilize the nation’s energy resources while ensuring reliable, affordable, and clean electricity..

Chapter 14: Regulating European Distribution Systems to Achieve Net Zero: Untapping Flexibility Efficiently

By Tim Schittekatte

The Transformation of European Distribution Grids

European distribution systems are at the epicentre of the energy transition. The push for net zero is driving a fundamental transformation, spurred by the rise of new technologies at the grid edge. These include a massive increase in **distributed generation** (DG), primarily rooftop solar PV; the electrification of transport and heating through **electric vehicles (EVs)** and **heat pumps**; and the growing deployment of **stationary storage**. Collectively known as Distributed Energy Resources (DERs), these technologies are turning passive consumers into active "prosumers" and creating new challenges and opportunities for Distribution System Operators (DSOs).

This transformation necessitates a two-pronged approach for DSOs and regulators. First is the massive, long-term expansion of distribution grid capacity to accommodate the deep electrification of the economy. Second, and the core focus of this chapter, is the development of a new regulatory toolbox to **cost-efficiently unlock flexibility** from DERs. Utilising this flexibility is crucial to manage grid constraints in the short term and to avoid or defer costly network reinforcements in the long term, thereby preventing over-investment and supporting an affordable energy transition.

A Regulatory Toolbox for Unlocking Flexibility

European regulation, particularly the 2019 Clean Energy Package, is actively promoting the development of three key regulatory tools to manage distribution grids more efficiently.

1. Distribution Network Access Tariffs

Network tariffs are the primary tool for recovering the costs of the distribution grid. Traditionally, for residential customers, these have been simple, flat volumetric charges (in €/kWh), often combined with net-metering for solar owners. This structure provides poor incentives for grid-friendly behaviour. The Clean Energy Package has pushed for reforms to make tariffs more **cost reflective**. The goal is to design tariffs that signal the true cost drivers of the network, which are primarily local network peaks. This encourages grid users to behave in ways that reduce the need for future investment. In practice, many EU member states are moving towards:

- **Capacity-based charges:** Charges based on a customer's maximum power demand (in kW) rather than just their energy consumption (in kWh). While a customer's individual maximum load does not necessarily align with the coincident peak load, this type of charge is deemed more cost reflective than a flat volumetric tariff, particularly when including a timing element.
- **Time-of-Use (TOU) volumetric charges:** Differentiating the €/kWh charge by time of day to encourage consumption to shift away from peak periods.
- A combination of both charges above.

While there is a clear trend towards more cost-reflective tariffs, progress is hampered by the incomplete rollout of smart meters, the complexity of calculating forward-looking costs, and the political sensitivity of tariff reforms that create winners and losers.

2. Smart Connection Agreements

A smart connection agreement offers a grid user a non-firm connection in exchange for a reduced connection fee or lower ongoing network access charges. This tool, also known as a flexible or interruptible connection, allows the DSO to curtail the user's demand or generation during periods of network congestion. This creates a win-win: the grid user gets a faster and cheaper connection, and the DSO avoids or defers a costly grid upgrade. This has been particularly useful for speeding up the connection of new renewable generation. The concept is also being extended to residential loads through load control programmes, for example, for managing EV charging or air conditioning, where consumers receive a bill discount in exchange for allowing the utility to control their appliance during a limited number of peak events.

3. Local Congestion Markets

The Clean Energy Package requires DSOs to consider procuring flexibility services through **market-based mechanisms** as an alternative to network expansion. This has led to the development of **local congestion markets**, often called flexibility markets. In these markets, the DSO acts as a buyer, procuring services (such as a temporary reduction in consumption or an increase in local generation) from DERs to resolve specific, localised network constraints.

Many pilot projects are underway across Europe, but their design is still evolving. Key open questions include:

- How should these local markets be integrated with the wider transmission-level balancing and wholesale markets?
- Who should own and operate the market platform (the DSO, a third party, or a consortium)?
- How can market power be mitigated, given that congestion is often highly localised, potentially giving a few DERs significant leverage?

4. Combining them as a toolbox for distribution-level flexibility

The chapter stresses that these three tools are not mutually exclusive and must be carefully coordinated. For instance, a highly effective set of network tariffs might reduce the frequency with which a DSO needs to intervene in a local congestion market. The optimal mix of these tools will vary depending on local circumstances.

The Evolving Regulatory Framework for DSOs

The shift towards active system management and flexibility markets is putting pressure on the broader regulatory framework governing DSOs.

- **Unbundling and Neutrality:** Current EU rules require DSOs with over 100,000 customers to be legally unbundled from competitive activities like generation and retail. The emergence of local congestion markets, where the DSO is the single buyer and potentially the market operator, raises new concerns about potential conflicts of interest and discriminatory behaviour. This is strengthening the arguments for stricter unbundling rules, potentially moving towards full ownership unbundling for larger DSOs.
- **Ownership of New Assets:** There is an ongoing debate about whether DSOs should be allowed to own assets like energy storage or EV charging stations. EU rules now stipulate that these assets should be market-based, with DSO ownership only permitted as a last resort if the market fails to deliver. This is to prevent DSOs from crowding out private investment and to ensure a level playing field.

TSO-DSO Coordination: Managing the Seams

As DERs become more numerous and capable, they can provide valuable services not just to the local distribution grid, but to the entire power system, such as participating in transmission-level balancing markets. This creates a critical need for much closer coordination between TSOs and DSOs.

The current division of tasks creates significant **"seams"** between the transmission and distribution systems, which risk leading to an inefficient use of DERs. For example, a DER providing a service to the TSO could inadvertently create a problem on the local distribution grid, or vice versa. The processes for DSOs to pre-qualify and manage the participation of DERs in TSO markets are still being developed and are often complex and administrative.

In the longer run, this challenge may necessitate a fundamental reorganisation of system operation tasks. Two alternative future visions are emerging:

1. **A "Super System Operator" Model:** In this model, the TSO's role would be expanded to include operational and market functions at the distribution level. This would internalise the TSO-DSO coordination challenge within a single entity, but would be computationally and organisationally complex.
2. **A "Local System Operator" Model:** In this model, DSOs would take on greater responsibility for balancing and managing all resources within their local area, acting as an aggregator at the T&D interface and interacting with the TSO in a more market-based way. This could foster local innovation but risks market fragmentation if not properly harmonised.

The path Europe will take is not yet clear, but it is evident that the traditional, siloed approach to TSO and DSO operations is not sustainable in a system with high levels of DERs. Overcoming the seams between transmission and distribution is a key regulatory challenge for efficiently achieving net zero

Chapter 15: "Behind the Meter" Developments

By Fereidoon Sioshansi

The Emergence of a New Electricity Domaine

For a century, the electricity system was simple: power flowed one way from large, central power stations, through the transmission and distribution networks, to a passive consumer's spinning meter. The utility's domain ended at the meter; what happened "**behind the meter**" (BTM) was of little concern. This paradigm is being fundamentally disrupted. A new "electricity domaine" has emerged BTM, driven by technological advances, digitalization and connectivity of electricity-consuming devices, new customer behaviour, and the urgent need to electrify and decarbonise. This BTM space is characterised by the rapid proliferation of customer-owned **Distributed Energy Resources (DERs)**, fundamentally changing the relationship between consumers, utilities, and the grid. This transformation requires a profound rethinking of electricity regulation.

Key BTM Developments

Several key trends are defining and driving the BTM landscape:

- **The Rise of the "Prosumager":** The traditional consumer is evolving. First came the **"prosumer",** who both consumes and produces energy, primarily through rooftop solar PV. In some regions, like Australia and California, solar penetration is already extremely high, with increasing numbers of households generating most if not all their own power needs. Now, with the falling cost of battery storage and the rise of electric vehicles (EVs), the **"prosumager"** is emerging—a customer who not only produces and consumes but also **manages and stores** energy. With the right combination of solar, storage, and EVs (some with bi-directional capabilities), a prosumager can be self-sufficient for over 90% of the year in sunny regions, drastically changing their need for traditional network services.
- **Digitalisation of Everything:** A second fundamental trend is the digitalisation and connectivity of virtually all BTM devices. Smart meters, smart thermostats, smart appliances, EV chargers, and inverters are increasingly becoming wirelessly connected to the internet. This allows them to be remotely monitored and controlled, either by the customer via an app or by a third-party service provider or aggregator. The combination of digitalisation and connectivity makes it possible to aggregate and optimise the performance of not thousands but millions of small, dispersed assets at virtually zero marginal cost. Advances in **Artificial Intelligence** (AI) makes it easy to monitor and optimise large numbers of devices.
- **New Coordination Mechanisms and Markets:** The combination of DERs and digitalisation is enabling new ways of coordinating energy use (or storage) at the local level.
  - **Microgrids and Energy Communities:** Groups of prosumagers can form local partnerships to jointly invest in, share, and trade energy. These microgrids can operate connected to the main grid or "island" themselves during an outage, providing enhanced local reliability and resilience.
  - **Virtual Power Plants (VPPs):** Aggregators can use software platforms to bundle together the capacity of thousands of individual BTM assets (such as distributed rooftop solar, batteries, smart water heaters, or EV chargers) into a VPP. This aggregated resource can then participate in the wholesale energy and ancillary service markets, providing services to the grid that would be impossible for any single device to offer.

- ○ **Transactive Energy:** This is an emerging concept where BTM devices can respond automatically to real-time price signals, creating a dynamic, market-based system for managing local energy flows. This moves beyond simple TOU rates to a "prices-to-devices" world, where an EV charger or a heat pump could directly bid into a local market or respond to a dynamic network tariff.

The Regulatory Challenge: Overhauling an Outdated System

These transformative BTM developments are running headlong into a regulatory system that was designed for a completely different era. Traditional regulation, based on the premise of a one-way power flow to passive customers paying a bundled volumetric tariff, is no longer fit for purpose for all, certainly not for prosumers or prosumagers. The BTM revolution challenges the regulatory status quo in several fundamental ways:

- **Rethinking the Role of the Network Operator:** Incumbent distribution system operators (DSOs) often view DERs as a nuisance that complicates grid management while reducing their revenues, rather than a valuable resource to be encouraged and cultivated when it is cost effective. Traditional rate-of-return regulation, which rewards utilities for capital investment in "poles and wires", can create a perverse incentive to oppose BTM solutions (often called "non-wire alternatives") even when they are more cost-effective. Regulation must evolve to incentivise DSOs to act as neutral platform facilitators, integrating DERs to provide services that lower overall system costs (rather than for some customers at the expense of others).
- **Fairness, Free-Riding, and Equity:** The rise of the prosumers and prosumagers creates significant equity challenges. Under traditional flat volumetric tariffs, a customer who installs solar panels and drastically reduces their net purchases from the grid also drastically reduces their contribution to the fixed costs of maintaining that grid, even though they still rely on it for backup and shortfalls in supply. This "free-riding" shifts costs onto other customers, often those with lower incomes or renters who are unable to install solar. This is forcing a fundamental rethink of retail tariff design, moving away from purely volumetric charges towards tariffs with higher fixed charges or demand-based charges that better reflect a customer's use of the network capacity. Regulators in jurisdictions like California, Australia, the UK and Hawaii are actively grappling with how to reform tariffs to ensure fair cost recovery without stifling the growth of DERs.
- **Enabling New Players and Business Models:** The BTM space is attracting a host of innovative new players, from solar and storage installers to VPP aggregators and microgrid developers. The regulatory framework must create a level playing field for these newcomers to compete and offer new services, while also managing the new conflicts of interest that frequently arise. This includes defining clear rules for third-party access to the grid and to customer data (with appropriate privacy protections).
- **Adapting Regulatory Tools:** Tools like Performance-Based Regulation (PBR) or the RIIO framework in Great Britain are being challenged and adapted. Regulators are exploring how to create incentives that reward DSOs for outcomes like successfully integrating DERs, facilitating local flexibility markets, and improving hosting capacity, rather than just for building more infrastructure, which they would otherwise favor.

In conclusion, the BTM space is no longer a passive appendage to the electricity system; it is becoming a vibrant, dynamic, and integral part of it. The customer is no longer just a "ratepayer" but an active market participant who can "strike back" against regulatory rulings through their own investment and operational choices. This requires a paradigm shift for regulators. They must move from a top-down, command-and-control mindset to one that embraces experimentation, enables competition, and focuses on designing the rules and platforms that will allow the full potential of the BTM revolution to be harnessed for the benefit of the entire system.

Chapter 16: Uncertainty, Regulation and the Pathways to Net Zero

By Michael G. Pollitt, Daniel Duma and Andrei Covatariu

The Challenge of Deep Uncertainty

Achieving net zero carbon emissions by mid-century is a policy goal fraught with deep and pervasive uncertainty. This uncertainty extends not only to the ultimate destination—the precise technological and economic configuration of a 2050 net zero system—but also, and more critically for current decision-making, to the pathway to get there. For energy regulators, who must make decisions today with consequences that will last for decades, managing this uncertainty is perhaps the single greatest challenge of the net zero era.

Net zero modelling often presents a range of plausible pathways, but these pathways themselves contain enormous variability. Key uncertainties include:

- **The Future Fuel Mix:** In economies with large natural gas networks, a fundamental uncertainty is the future of gas. Will it be largely phased out in favour of electrification? Or will gas networks be repurposed to carry low-carbon fuels like hydrogen or biomethane? The implications for investment in both gas and electricity networks are vastly different under these scenarios.
- **The Pace of Electrification:** The speed at which transport and heating are electrified is highly uncertain. The timing of a significant uptake of electric vehicles and heat pumps will have a large impact on electricity demand and the required investment in generation and networks.
- **Technological Surprises:** The path to net zero has been aided by positive technological surprises, such as the rapid cost decline of solar, wind, and batteries. However, it is threatened by the underperformance of other key technologies like carbon capture and storage (CCS) and clean hydrogen. Future "wildcard" technologies, like nuclear fusion or breakthroughs in artificial intelligence, could fundamentally alter the trajectory.
- **Macroeconomic and Geopolitical Shocks:** The size of the future economy, population growth, extreme weather events, global crises like pandemics, and geopolitical shifts in climate policy all add further layers of uncertainty that regulators must navigate.

Net Zero and the Regulatory Trilemma

This environment of deep uncertainty heightens the inherent trade-offs, or "trilemmas", that regulators face.

The traditional **energy trilemma** involves balancing affordability, security of supply, and environmental sustainability. Net zero adds a hard constraint on the environmental dimension, which inevitably puts upward pressure on costs and creates new reliability challenges.

A second **regulatory trilemma** exists between the **effectiveness** of regulatory incentives, the **responsiveness** of the regulation to new information, and the **coherence** and predictability of regulatory decisions. Strong, fixed, long-term incentives (high effectiveness) can motivate companies, but they are not responsive to new information and can lead to poor outcomes if initial assumptions prove wrong. A highly responsive system that constantly adapts may lack the coherence and predictability needed to encourage long-term investment. Net zero sharpens this second trilemma. The high uncertainty demands greater responsiveness, but the need for massive, long-term investment demands coherence and predictability.

A New Approach: The "Learning Regulator"

To navigate these challenges, this chapter argues for the need to move towards a **"learning regulator".** A learning regulator is one that explicitly and systematically incorporates learning from the past, the present, and the future into its decision-making processes. This approach is built on three concepts from the wider literature on regulation:

1. **Dynamic Regulation (Learning from the Past):** This involves efficiently incorporating information from previous regulatory cycles to improve future decisions. For example, analysing past performance on cost savings or output delivery can inform the setting of more accurate benchmarks and incentives for the next period. It also means focusing on incentives for long-term investment and innovation, not just short-term optimisation.
2. **Responsive Regulation (Learning from the Present):** This moves beyond a simple command-and-control or reward-and-punishment approach. It actively encourages **stakeholder participation** to co-create regulatory solutions. By engaging with companies, consumers, and other experts, the regulator can gather real-time information and foster positive social norms, finding a middle ground between rigid rules and complete self-regulation. Leading regulators in Great Britain (GB) and Australia already make extensive use of stakeholder challenge groups and public consultations.
3. **Adaptive Regulation (Learning from the Future):** This is the most novel and crucial element for managing net zero uncertainty. Instead of making large, one-off decisions based on uncertain long-term forecasts, adaptive regulation breaks decisions down into a series of **partial, sequential and indefinite steps**. It explicitly identifies key future uncertainties and establishes pre-defined **"trigger points"** or "signposts". When new information becomes available and a trigger point is reached, it prompts a pre-planned regulatory review or adjustment. For example, a regulator might approve a baseline level of investment in the gas network (a "no-and-low-regret" core pathway). It would also identify a trigger point, such as the government making a firm decision on the future role of electric heat pumps in heating. If that trigger occurs, it would automatically initiate a pre-defined process to review and potentially approve a higher level of investment (an "alternative pathway"). This approach allows the regulator to commit to a stable baseline while building in the flexibility to adapt as key uncertainties are resolved.

The Importance of Institutional Context

A learning regulator cannot operate in a vacuum. Its success depends on being part of the right institutional context.

- **A Clear Division of Labour:** The regulator's role must be clearly defined in relation to other key actors. Government ministries must be responsible for making the big, fiscally significant policy decisions (like the role of hydrogen). A suitably empowered and independent **system operator** is needed to manage the system in real time and undertake trusted, impartial indicative planning. The regulator's role is to then design the detailed economic incentives and rules to implement these high-level policies efficiently.
- **Structural and Ownership Reform:** The alignment of incentives can be improved through changes to the structure and ownership of the energy sector itself. As discussed in other chapters, this could involve creating a publicly-owned Future System Operator (as in GB), or reorganising gas and

electricity network ownership to better coordinate local decarbonisation.

In conclusion, the path to net zero is not a predictable engineering exercise but a journey through a landscape of deep uncertainty. Traditional, static regulatory approaches are ill-equipped for this challenge. By embracing the principles of a "learning regulator"—systematically incorporating lessons from the past, present, and the future—and operating within a well-designed institutional framework, economic regulation can become a more robust and effective tool for navigating the uncertain pathways to a decarbonised energy future.

Chapter 17: How Can Regulated Electricity Network Companies Promote Innovation? Lessons from the Field of Practice

By Leonardo Meeus and Nicolò Rossetto

The Innovation Challenge for Monopolies

Innovation is often driven by the necessity of competition. Firms innovate to differentiate their products, reduce their costs, and capture market share. Regulated monopoly network companies, however, are shielded from these direct competitive pressures. Their primary mandate is to "keep the lights on" reliably and securely, a mission that naturally fosters a conservative, risk-averse culture rather than one of experimentation. Their prices are regulated, limiting their ability to capture the extraordinary profits that can reward successful innovation in competitive markets.

Despite this, it is not only possible but essential for regulated network companies to innovate. The energy transition demands new technologies, smarter operational practices, and new business models to integrate renewable energy, electrify new sectors, and manage an increasingly complex grid. This chapter explores why network companies can and should innovate, and how regulators can create a framework that promotes this innovation.

There are three primary reasons why even a monopoly network company has an incentive to innovate:

1. **An Evolving Mandate:** The role of the network company is not static. Regulators can expand or redefine their mandate, for example, by tasking them with operating a smart meter data hub or facilitating local flexibility markets. A company's reputation and demonstrated ability to innovate can influence its chances of being awarded these valuable new responsibilities.
2. **Interaction with Commercial Activities:** Network companies are often part of larger holding companies with commercial interests. While unbundling rules exist to limit conflicts of interest, a network company can still develop commercial businesses, such as providing consultancy services or selling software solutions to other utilities worldwide. The expertise gained through innovation in their regulated business can become a valuable commercial asset.
3. **Financial Incentives from Regulators:** This is the most direct and powerful lever. Regulators can design financial incentives that explicitly reward innovation and penalise stagnation.

The Dual Role of Network Companies in Innovation

The innovative role of a network company is twofold. They must not only innovate within their own core business but also act as enablers of innovation across the entire electricity system.

- **Innovation in the Network Business:** This involves finding new and better ways to plan, build, and operate the network itself.
    - **Smart Grids:** The transition from a passive "fit and forget" approach to an active, "smart grid" paradigm is a massive innovation challenge. It requires DSOs to adopt new sensors, control systems, and data analytics to manage bi-directional power flows and leverage flexibility from DERs.
    - **Super Grids:** At the transmission level, building international and offshore "super grids" to

connect the best renewable resources to demand centres requires technological innovation (e.g., in HVDC technology) and, just as importantly, institutional innovation in cross-border planning and cooperation.
    - **Public Acceptance:** Faced with growing local opposition to new infrastructure, network companies must innovate in their stakeholder engagement processes, moving from simple consultation to genuine co-creation of solutions with affected communities.
- **Enabling System Innovation:** Network companies are central gatekeepers in the electricity system. Their actions can either facilitate or stifle innovation by market parties.
    - **Integrating Renewables:** TSOs have played a crucial role in innovating balancing markets, developing new products, and creating platforms that have enabled the successful integration of large volumes of intermittent renewables.
    - **Facilitating Aggregators:** The emergence of independent aggregators, who create virtual power plants from customer-owned DERs, required network operators (primarily TSOs) to innovate their market rules to define the roles and responsibilities of these new players and give them fair access to markets. As local congestion markets develop, DSOs will need to play a similar enabling role.

Regulatory Tools to Promote Innovation

Regulators have a suite of tools they can use to encourage network companies to embrace both of these innovative roles. These tools can be categorised into three main types, mirroring the reasons why networks innovate.

1. Adjusting the Mandate

Regulators can use the threat of reducing a company's mandate or the promise of expanding it as a powerful, non-financial incentive. For example, the ongoing debate in many jurisdictions about whether to separate system operation from network asset ownership (creating an Independent System Operator) acts as a credible threat to incumbent network companies. If they fail to operate the system innovatively and impartially, they risk losing that part of their business. Conversely, by demonstrating competence and innovation, a network company can position itself as the best candidate to take on new regulated tasks, such as managing a national energy data hub.

2. Regulating Commercial Activities

While unbundling rules are in place, regulators can still influence the commercial activities of network companies. Allowing a network company to establish a separate, commercial arm to sell its innovative solutions and expertise on the open market can create a strong profit-driven incentive for innovation within the regulated core business. This can be positive, but regulators must remain vigilant for new conflicts of interest and ensure there is no cross-subsidisation from the regulated business to the competitive one.

3. Designing Financial Incentives

This is the most direct approach. Regulation has evolved from simply providing implicit incentives for innovation through cost-saving mechanisms to designing explicit, targeted incentives.

- **Incentives for Cost Savings:** Revenue or price cap regulation (like RPI-X or RIIO) provides a basic incentive to innovate to reduce costs. By allowing the company to keep a share of any efficiency savings for a period, the regulator rewards process innovation. However, this can have perverse effects, as it can discourage riskier, long-term R&D projects in favour of short-term, certain cost reductions.

- **Incentives for Outputs:** Output-based regulation (a key feature of RIIO) rewards companies for achieving specific performance targets. This is technology-neutral and incentivises the company to find the most innovative solution to deliver a desired outcome, such as improved reliability or faster connection times.
- **Targeted Innovation Stimuli:** Recognising that general cost and output incentives may not be sufficient, many regulators have introduced dedicated innovation funding schemes. These can take several forms:
    - **R&D Allowances:** Allowing the company to pass through the costs of a limited R&D budget.
    - **Competitive Funding:** Establishing a central fund (like the UK's Network Innovation Competition) for which companies can bid to finance large, collaborative innovation projects.
    - **Higher Rates of Return:** Offering a higher allowed return on investments in specific, innovative technologies to compensate for their higher risk.
    - **Regulatory Sandboxes:** This is an increasingly popular tool. A sandbox provides a "safe space" where a company can test an innovative service, technology, or business model with real customers for a limited time, with a temporary exemption from certain existing rules that might otherwise be a barrier. This allows both the company and the regulator to learn from real-world experimentation before deciding on permanent rule changes.

In conclusion, while regulated network companies may not face the same existential pressures to innovate as firms in competitive markets, they can and must be active participants in the innovation system. It is the regulator's role to create a framework that moves beyond a narrow focus on static efficiency and instead provides a multi-faceted set of incentives—through the company's mandate, its commercial opportunities, and its direct financial rewards—that encourages the continuous innovation needed to deliver a secure, affordable, and clean energy future.

Chapter 18: Regulation of Hydrogen Networks and Potential Market Structure

By Chi Kong Chyong and Jackson R. Dalman

The Emerging Role of Low-Carbon Hydrogen

Hydrogen is gaining significant attention as a critical clean energy carrier for achieving net zero emissions. While it currently represents a tiny fraction of the global energy mix, low-carbon hydrogen and its derivatives (like ammonia) are seen as vital for decarbonising "hard-to-abate" sectors where direct electrification is difficult or uneconomic. These include heavy industry (e.g., steel and chemical production), heavy-duty transport, and long-duration energy storage.

Governments worldwide, particularly in the US and Europe, are actively promoting the development of a clean hydrogen economy through ambitious strategies, targets, and financial incentives. However, the construction of projects is lagging, partly due to the high costs and the lack of a clear regulatory framework for the necessary infrastructure, especially hydrogen pipelines.

There are two main pathways to producing low-carbon hydrogen:

1. **Green Hydrogen:** Produced via electrolysis, splitting water into hydrogen and oxygen using renewable electricity. This is the cleanest pathway, but currently the most expensive.
2. **Blue Hydrogen:** Produced from natural gas using Steam Methane Reforming (SMR), with the resulting CO_2 emissions captured and stored (CCS). This can be cheaper in the short term, especially in regions with low natural gas prices, but its climate benefit depends critically on high CO_2 capture rates and low methane leakage from the gas supply chain.

As policy and technology evolve, green hydrogen is expected to become more cost-competitive and is the focus of most long-term net zero strategies.

Regulating Hydrogen Pipelines: A Natural Monopoly Challenge

Similar to natural gas pipelines, hydrogen pipelines exhibit the characteristics of a **natural monopoly** due to their high capital costs and economies of scale. This creates a clear economic rationale for government regulation to ensure fair access and prevent monopolistic pricing. The core principles of pipeline regulation should include:

- **Third-Party Access (TPA):** Ensuring fair and non-discriminatory access for all producers and consumers.
- **Transparent Tariffs:** Establishing a clear and economically justified methodology for setting transport tariffs.
- **Unbundling:** Separating the pipeline operation from competitive hydrogen production and supply activities to prevent anti-competitive behaviour.
- **Efficient Investment:** Creating incentives for the efficient maintenance and expansion of the network.

Europe and the US are taking different approaches to establishing this regulatory framework, largely mirroring their existing regimes for natural gas.

The European Approach: Building on the Gas Model

The EU is moving decisively to create a regulatory framework for hydrogen, laid out in its **Hydrogen and Decarbonised Gas Market package**. The approach is to explicitly model the new hydrogen regulations on the existing framework for the EU internal natural gas market.

Key features of the EU approach include:

- **Mandatory Third-Party Access:** Hydrogen pipelines will be treated as common carriers, with mandatory TPA to ensure access for all market participants.
- **Unbundling:** The rules for unbundling hydrogen network operators from production and supply will mirror those for natural gas TSOs.
- **European Network Planning:** A new European Network of Network Operators for Hydrogen (ENNOH) will be established to coordinate cross-border network planning.
- **Elimination of Cross-Border Tariffs:** To avoid the problem of "tariff pancaking" (where tariffs accumulate as hydrogen crosses multiple borders), the EU proposes to eliminate intra-EU transport tariffs for dedicated hydrogen networks and offer significant discounts for hydrogen transported on the existing gas grid.

While this approach provides regulatory certainty, it risks replicating some of the known inefficiencies of the European gas model. The complex revenue-sharing required to eliminate cross-border tariffs while still allowing TSOs to recover their costs could prove difficult to implement efficiently. The EU's "top-down" approach of imposing a regulatory model before a substantial market has even developed contrasts sharply with the more organic, market-driven evolution of the US gas market.

The US Approach: Regulatory Uncertainty

In contrast to the EU, the US currently lacks a clear regulatory structure for interstate hydrogen pipelines. There is significant legal uncertainty over which federal agency has jurisdiction and which statute should apply.

- **The Jurisdictional Question:** The presumptive regulator is the **Federal Energy Regulatory Commission (FERC)**, which regulates interstate natural gas and oil pipelines. However, there is no explicit law giving FERC authority over hydrogen. It is unclear whether hydrogen would be regulated under the **Natural Gas Act (NGA)** or the **Interstate Commerce Act (ICA)**, which governs oil pipelines. The choice has profound implications.
- Regulation under the NGA (like natural gas) would give FERC strong powers over construction and siting, including the ability to pre-empt state laws and grant eminent domain. The NGA has facilitated a system of **private/contract carriage**, where pipeline capacity is primarily allocated through bilateral negotiations, which has led to a highly efficient and competitive US interstate gas market.
- Regulation under the ICA (like oil) would mean treating pipelines as **common carriers**, with weaker federal siting authority.

This regulatory uncertainty is a significant barrier to investment. The most straightforward solution would be for the US Congress to pass legislation granting FERC explicit jurisdiction and clarifying the regulatory model. Given the success of the US natural gas market, there is a strong argument for regulating hydrogen pipelines under a similar regime to the NGA, allowing for Coasian bargaining and flexible access arrangements rather than a rigid common carriage model.

Potential Market Structures and Business Models

Currently, there is no organised wholesale market for hydrogen. Most hydrogen is produced and consumed "on-site" by industrial users in a vertically integrated fashion. The evolution towards a liberalised market is likely to see the emergence of several business models for producing and procuring green hydrogen.

- **Vertical Integration:** A green hydrogen producer could directly own its own renewable generation assets (e.g., a dedicated wind farm). This minimises counter-party risk but is highly capital-intensive.
- **Power Purchase Agreements (PPAs):** A hydrogen producer could sign a long-term PPA with a renewable generator. This is less capital-intensive but requires careful contract structuring to manage risks. A key challenge here is ensuring **"additionality" and "temporal correlation"**—the principles that the renewable electricity used is truly new and is generated at the same time the hydrogen is produced. This is leading to the development of 24/7 tracking of renewable energy certificates.
- **Hybrid Sourcing:** A producer could use a mix of PPAs and purchasing power directly from the wholesale market, particularly during hours when renewable energy is abundant and prices are very low or even negative. This model also allows the electrolyser to provide valuable flexibility services back to the power grid, creating an additional revenue stream.
- **Long-Term Offtake Contracts:** A "supply-led" model could emerge where a hydrogen producer (e.g., an electric utility) builds an electrolysis plant and secures demand through long-term, take-or-pay contracts with industrial users, similar to traditional LNG contracts.
- **Merchant (Tolling) Model:** An investor could build a standalone electrolysis plant and sell its "processing" or "tolling" capacity to customers (e.g., utilities or industrial users), who would be responsible for sourcing their own electricity and water. This model, analogous to US LNG export terminals, separates commodity risk from capacity risk and could thrive in areas with deep and liquid wholesale power markets.

In conclusion, while governments have ambitious plans for hydrogen, the path to a mature, competitive market is long and filled with regulatory and commercial challenges. Europe has chosen a clear but potentially rigid regulatory path based on its gas market model. The US faces significant regulatory uncertainty that is hindering investment. The most efficient pathway is likely to involve a regulatory framework that encourages dynamic efficiency and allows a variety of business models to emerge, leveraging the deep integration between the future hydrogen economy and an increasingly renewable-powered electricity grid.

Chapter 19: Challenges to Expanding EV Adoption and Policy Responses

By Christopher R. Knittel and Shinsuke Tanaka

The Critical Role of EVs and the Adoption Challenge

Decarbonising the transportation sector is a critical pillar of global efforts to combat climate change. In the US, transportation is now the largest source of greenhouse gas emissions. The widespread adoption of electric vehicles (EVs) offers the most compelling pathway to eliminate tailpipe emissions, but this transition must be paired with the decarbonisation of the electricity grid to achieve its full climate benefit.

The global EV market is growing at a remarkable rate, with sales surpassing 10 million in 2022. However, adoption rates vary significantly. In leading countries like Norway, EVs account for over 80% of new car sales. In contrast, the US, despite being a major market, lags behind, with EVs making up only around 6% of new light-vehicle sales in 2022, well short of the Biden administration's target of 50% by 2030.

This chapter focuses on a primary barrier to more rapid EV adoption: the need for a robust and accessible **EV charging infrastructure**. While this review primarily examines policies related to charging infrastructure, it also provides an overview of policies aimed at directly incentivising EV adoption, as the two are inextricably linked.

Key Barriers to EV Adoption

Three major barriers have historically impeded the transition to EVs:

1. **High Upfront Cost:** EVs are typically more expensive to purchase than comparable internal combustion engine (ICE) vehicles, largely due to the cost of the battery. While battery costs have fallen dramatically and price parity is projected within the next decade, this initial cost difference remains a significant hurdle for many consumers.
2. **Range Anxiety:** This is the fear of running out of battery power before reaching a destination or a charging station. While the driving range of modern EVs has increased significantly and now meets the daily needs of the average driver, the perception of limited range persists, especially for long-distance travel.
3. **Lack of Charging Infrastructure:** This is arguably the most critical barrier today. While most EV owners do the majority of their charging at home, the lack of a comprehensive and reliable **public charging network** is a major concern. It is essential for drivers who live in apartments or lack private parking, and it is crucial for enabling long-distance travel and alleviating range anxiety for all drivers.

Policy Initiatives for EV Charging Infrastructure in the US

The US has implemented a series of federal, state, and utility-level policies to accelerate the deployment of charging infrastructure.

- **Federal Policies:**
  - **American Recovery and Reinvestment Act (ARRA) of 2009:** This was the first major federal effort, providing funding that helped establish an initial network of over 17,000 chargers.
  - **The Bipartisan Infrastructure Law (BIL) of 2021:** This represents a landmark investment. The BIL allocates **$7.5 billion** specifically for EV charging, with the goal of building a national network of 500,000 chargers by 2030. This funding is distributed through two main programmes:
    - **National Electric Vehicle Infrastructure (NEVI) Formula Program ($5 billion):** This provides funds to states to build a network of DC fast chargers along designated "Alternative Fuel Corridors" (major highways), with stations required every 50 miles and within one mile of the highway.
    - **Charging and Fueling Infrastructure Discretionary Grant Program ($2.5 billion):** This provides competitive grants for charging projects in communities, with a focus on rural, low-income, and disadvantaged areas that might otherwise be overlooked by private investment.
  - **Inflation Reduction Act (IRA) of 2022:** The IRA renewed and expanded the **Alternative Fuel Refueling Property Tax Credit**. This provides a tax credit of up to 30% (capped at $100,000 for businesses) for the cost of purchasing and installing charging equipment, with enhanced credits for projects that meet labour standards or are located in low-income or rural areas.
- **State and Utility Policies:**
  - States and regulated utilities are playing a vital role, often going beyond the federal initiatives. California, a long-time leader, has multiple programmes like CALeVIP, which provides regional rebates for charger installation, and has mandated that new buildings be "EV-ready".
  - Many states are also tackling the challenging economics of public charging. The high upfront cost of DC fast chargers, combined with low utilisation rates in the early stages of market development, can make them unprofitable for private operators. In response, states like New York and Massachusetts are approving new utility rate designs and incentives to reduce the operating costs for charging station owners, for example, by providing rebates on demand charges, which can be a major cost component.

The Global Context

Other countries offer valuable lessons. **Norway's** success is built on a combination of massive tax incentives for EV purchases and significant public investment to build out a dense charging network, including fast chargers every 50 kilometres on major roads. **China**, now the world's largest EV market, has overcome initial challenges to build the world's largest public charging network, supported by national targets, unified technical standards, and substantial subsidies. China is also a pioneer in **battery swapping** technology.

Policy Challenges for the Future

Despite recent progress, significant policy challenges remain in building out an efficient, equitable, and reliable charging network.

- **The "Chicken or Egg" Problem:** What comes first, the EVs or the chargers? Private companies are hesitant to invest in chargers without a critical mass of EVs on the road to ensure profitability. But consumers are hesitant to buy EVs without a visible and reliable charging network. Recent research suggests that subsidising charging infrastructure is more cost-effective in driving EV adoption than subsidising EV purchases, highlighting the importance of public investment in breaking this cycle.
- **Compatibility and Standardization:** A "plug war" has been a major issue in the US, with three incompatible DC fast charging standards (CCS, CHAdeMO, and Tesla's NACS). This creates consumer confusion and market fragmentation. However, a market-led standardization is now rapidly occurring, with nearly all major automakers announcing they will adopt Tesla's NACS connector for their North American vehicles starting in 2025. This will significantly improve the user experience, but it creates a policy challenge as the federal NEVI program currently mandates the inclusion of a CCS connector.
- **Equity and Distributional Concerns:** Public charging infrastructure is currently concentrated in more affluent areas. This creates an "amenity desert" in low-income and minority communities, creating a barrier to EV adoption for those who could benefit most from lower fuel and maintenance costs. Federal and state programmes are increasingly focused on targeting investment in these underserved communities, but analysis shows there is still a significant disparity.
- **Grid Burden:** The widespread adoption of EVs will increase electricity demand and could strain the local distribution grid if charging is unmanaged. The key challenge is to manage the *timing* of charging. Uncoordinated charging, especially during evening peak hours, could require costly grid upgrades. The solutions involve strategic deployment of workplace charging (to absorb midday solar generation), and policies that encourage **smart charging**. This includes time-of-use electricity rates that make off-peak charging cheaper, and technologies that allow utilities or aggregators to manage charging times to avoid grid stress.

In conclusion, building the EV charging infrastructure America needs is a complex undertaking that requires a coordinated effort between federal, state, and local governments, utilities, and the private sector. While recent federal legislation has provided a massive injection of funding, success will depend on addressing the key policy challenges of strategic deployment, standardization, equity, and effective grid integration.

Part III: Non-OECD Countries

Chapter 20: Power Sector Reform in China: Economic Logic and Political Reasoning

By Xu Yi-chong

A Four-Decade Journey of Incomplete Reform

Power sector reform has been a policy priority in China for over forty years, yet it remains a work in progress. While China has long accepted the economic logic that its power sector is inefficient and could benefit from market mechanisms, competition, and independent regulation, it has consistently resisted fully embracing the reform models seen in the West. This chapter argues that the key to understanding this long and often contradictory saga lies not just in economic analysis, but in grasping the overriding **political reasoning** of the Chinese Communist Party (CCP): the imperative **"to be and be seen in control".**

The reform journey can be broadly categorised into four rounds, each catalysed by different challenges but all shaped by this central political objective.

1. **1980s-1990s (Decentralisation and Corporatisation):** The initial reforms were not about creating markets but about solving a crippling power shortage that threatened economic growth. The government lowered entry barriers to generation, allowing provinces and enterprises to invest. This successfully spurred a massive expansion of capacity. By the late 1990s, the focus shifted to corporatising the industry, culminating in the creation of the monolithic State Power Corporation of China (SPCC), which inherited most of the state's power assets.
2. **2002 (Unbundling):** The next major reform (Document 5) dismantled the SPCC. Its assets were unbundled and redistributed to two new grid companies, five large generation groups, and several service companies. This move was presented as a step towards creating a competitive market. Crucially, it also created the State Electricity Regulatory Commission (SERC), China's first attempt at an independent regulator.
3. **2015 (Deepening Reform):** The most recent round of reform (Document 9) was launched to address deep-rooted problems that had persisted, including low efficiency, severe curtailment of renewable energy, and the lack of market-based pricing. The plan outlined ambitious steps, including building power markets, setting up power exchange centres, introducing competition in the retail sector, and opening up investment in new distribution networks.

The Elusive Goal: Separating Government from Enterprise

Despite four decades of reform, a consistent stated objective has been the "separation of government and enterprise functions". This goal has remained elusive. The Chinese system is characterised by a deep and persistent entanglement of the state, the CCP, and the state-owned enterprises (SOEs) that dominate the power sector.

The 2002 reform, for example, created a dysfunctional and overlapping governance structure. The newly created power companies were nominally owned and supervised by the State-owned Asset Supervision and Administration Commission (SASAC), which incentivised them to operate as profit-seeking corporations. However, their investment decisions and prices remained under the tight control of the powerful central planner, the National Development and Reform Commission (NDRC). At the same time, they were supposed to be regulated by the newly created SERC, which was given high status but no real authority or capacity to challenge the NDRC or the powerful SOEs.

This fractured governance allowed the large power companies to expand dramatically, often playing different government agencies off against each other. By the 2010s, this had led to massive overcapacity in thermal power generation, low plant utilisation rates, severe environmental pollution, and the aforementioned curtailment of wind and solar power.

The Irony of the 2015 Reform: Central Control to Release Market Forces

The 2015 reform was part of a broader shift in Chinese governance under the principle of **"top-level design".** This approach emphasises highly centralised control by the CCP over the entire reform agenda, with the Party setting priorities, coordinating implementation, and enforcing strict discipline. The profound irony is that this highly centralised power was deployed to introduce decentralised, individualistic market forces. This created fundamental contradictions. For example:

- **The Role of the NDRC:** The reform called for market-based pricing, which would require the NDRC to relinquish its authority over setting power tariffs. However, the NDRC, as the central planner and the drafter of the reform itself, had no intention of giving up this crucial tool of macroeconomic control. The long-standing problem of "market coal, planned power"—where power generators were squeezed between market-based coal prices and state-set electricity tariffs—persisted, leading to huge financial losses for thermal producers.
- **Private Participation:** The reform aimed to introduce private capital, particularly in new distribution networks and retail services. However, at the same time, the CCP was strengthening its influence over all enterprises through a "party-building" policy. This, combined with arbitrary government interventions (such as forcing grid companies to absorb tariff reductions for industrial customers), sent conflicting signals to private investors. After an initial wave of interest, private investment largely retreated, leaving the new opportunities to be dominated by existing SOEs.

The Missing Pillar: An Independent Regulator

Perhaps the most significant failure of China's power sector reform has been the inability to establish a credible, independent regulatory institution. While setting up a regulator is often one of the first and easiest steps in other countries, in China it has proven exceptionally difficult.

The SERC, created in 2002, was ultimately a failed experiment. It lacked the authority, resources, and political backing to enforce its mandate. It was abolished in 2013, and its functions were absorbed back into the National Energy Administration (NEA), which itself is embedded within the powerful NDRC. This precludes any genuine independence.

The fundamental stumbling block is political. An independent regulator, operating under a clear legal framework and enforcing rules transparently and consistently, is antithetical to the CCP's insistence on maintaining discretionary control and being the ultimate arbiter. The government seeks a system where the state and markets play "complementary" roles, but in practice, this means the state reserves the right to intervene directly through top-down orders rather than submitting to a rule-of-law-based regime. The outdated Electric Power Law of 1995 has not been meaningfully revised to reflect the realities of a restructured industry, leaving players to operate in a legal grey area.

Conclusion: An Unfinished and Unconventional Path

China's four-decade-long power sector reform has produced a system that is a hybrid of plan and market, state control and corporate profit-seeking. The reforms have been "problem-oriented", responding to specific crises like power shortages or renewable curtailment, rather than being driven by a consistent commitment to a market-based paradigm.

While the system has impressively delivered universal access to reliable and affordable electricity for 1.4 billion people and has built the world's largest renewable energy capacity, it has done so with persistent inefficiency and without creating the software—the market institutions and independent regulation—needed for a truly modern power system. The policy bottom line, to ensure electricity serves the state's broader economic and social development goals, has consistently trumped the economic objectives of optimal investment and operation. The CCP's core political logic dictates that it will not cede final control to an independent regulator or to the unconstrained forces of the market. The reform, therefore, remains profoundly incomplete.

Chapter 21: Regulation of Transmission, Distribution and Retail in India

By Anupama Sen and Tooraj Jamasb

The Indian Context: A Dual Challenge

India's electricity sector stands at a critical juncture, facing the dual challenge of meeting the rapidly growing energy demands of the world's most populous nation while simultaneously pursuing an ambitious decarbonisation agenda. As the third-largest electricity producer and carbon emitter, India's path is crucial to global climate efforts. The country has set a target of net zero emissions by 2070 and aims to have 50% of its installed capacity from non-fossil fuel sources by 2030.

This transition is taking place within a complex regulatory and political landscape. Under India's constitution, electricity is a "concurrent subject", giving both the federal (central) government and the 28 state governments significant autonomy. This has led to a varied and often fragmented approach to policy and regulation across the country. While the federal level has made significant strides, particularly in generation, the downstream segments—transmission, distribution, and retail—remain fraught with challenges, many of which are a legacy of the old state-run system.

The Evolution of Reform and Regulatory Architecture

India's power sector has evolved through several distinct phases:

- **The State Electricity Board (SEB) Era (Post-1947):** For decades after independence, the sector was dominated by large, vertically integrated, state-owned SEBs. Their primary mission was rural electrification. However, they were plagued by inefficiency, high losses, and political interference, particularly the setting of agricultural tariffs far below the cost of supply, which rendered them financially insolvent.
- **Liberalisation and Unbundling (1990s-2003):** Spurred by a national economic crisis in 1991, reforms began with the opening of generation to private investment. The landmark **Electricity Act of 2003** provided the blueprint for a modern, market-oriented sector. It mandated the unbundling of the SEBs, deregulated generation, and established a new regulatory architecture with an independent **Central Electricity Regulatory Commission (CERC)** at the federal level and **State Electricity Regulatory Commissions (SERCs)** in each state.
- **Competition and Renewables (2010-Present):** This period has been marked by a massive expansion in renewable energy capacity, primarily driven by a federal policy of competitive **reverse auctions** for wind and solar projects. This has been a major success, dramatically lowering the cost of renewables. However, the downstream challenges have persisted.

The State of Play: A Sector of Contrasts

- **Generation (A Success Story):** The generation sector is now highly diverse, with a mix of central, state, and private ownership. Competitive auctions for renewables have been exceptionally successful, attracting investment and driving down prices. Wholesale power trading occurs on two national power exchanges, although the majority of power is still sold through long-term Power Purchase Agreements (PPAs).
- **Transmission (Mixed Progress):** The transmission network has been unbundled, with a Central Transmission Utility at the federal level and State Transmission Utilities. The five regional grids have been synchronised into a single national grid, a major achievement. "Green energy corridors" are being built to evacuate power from renewable-rich states. However, investment has struggled to keep pace with the growth in generation, leading to congestion.
- **Distribution and Retail (The "Weakest Link"):** This remains the most problematic segment. The Act of 2003 envisioned the separation of distribution (wires) and retail supply, but in practice, they remain integrated. The vast majority of distribution is handled by state-owned **distribution companies (discoms)**, the successors to the SEBs. These discoms are in a state of perennial financial crisis due to a combination of factors:
    - **Non-Cost-Reflective Tariffs:** SERCs, often under political pressure, have failed to allow tariffs, particularly for agricultural and residential consumers, to rise to levels that cover the cost of supply.
    - **High Losses:** Aggregate Technical and Commercial (AT&C) losses, which include both technical inefficiencies and power theft, remain high, averaging around 22% nationally.
    - **Subsidy Delays:** State governments are often late in paying the subsidies owed to discoms to compensate for below-cost tariffs.

The federal government has repeatedly bailed out the discoms through debt restructuring schemes (most recently, the UDAY programme), but these have failed to solve the underlying structural problems.

The Push for a New Wave of Reform

Recognising that the discom crisis is a major impediment to the energy transition, the federal government has proposed a new set of reforms, primarily through the **Electricity (Amendment) Bill 2022** and the **Electricity (Rights of Consumers) Rules 2023**. These proposals aim to tackle the legacy issues head-on. Key provisions include:

- **Enforcing Financial Discipline:** The Bill seeks to impose hard budget constraints on discoms. It mandates cost-reflective tariffs and proposes that subsidies be paid directly to consumers via cash transfers (Direct Benefit Transfers), rather than through the discoms. It also seeks to ensure that discoms provide adequate payment security before they are allowed to schedule power.
- **Introducing Retail Competition:** A key and controversial proposal is to enable competition in retail supply. The Bill would allow discoms to appoint "distribution sub-licensees", effectively allowing multiple retail suppliers, including private companies, to operate within a single discom's area, using its network on an open access basis.
- **Strengthening Contract Enforcement:** A new Electricity Contracts Enforcement Authority (ECEA) would be established to adjudicate disputes related to PPAs, a response to attempts by some discoms to unilaterally renegotiate contracts with renewable developers.
- **Strengthening Federal Oversight:** The Bill proposes to give the federal government a greater role in the appointment of state regulators, a move seen by many states as an infringement on their

constitutional authority.

- **Empowering "Prosumers":** The new Consumer Rules aim to simplify the process for customers to install rooftop solar and other DERs, defining their rights as "prosumers" who can both consume and inject power into the grid. It also promotes smart metering and time-of-use tariffs to encourage demand flexibility.

Challenges and the Path Forward

These proposed reforms are a bold attempt to address the deep-seated problems in India's electricity sector. However, they face significant political opposition from state governments, who view them as an overreach of central authority, and from consumer groups and unions who fear privatisation and tariff hikes.

The success of India's energy transition hinges on resolving these downstream challenges. While the country has excelled at adding renewable generation capacity, the grid and the retail sector must be modernised to integrate it effectively. The case of **Gujarat**, a top-performing state, demonstrates that successful reform is possible. Through a combination of strong political will, technical and commercial reforms to reduce losses, regular tariff revisions by an empowered SERC, and innovative policies to promote renewables, Gujarat has transformed its once-ailing SEB into a set of profitable and efficient discoms.

Looking ahead, India may need to move towards a **Distribution System Operator (DSO)** model, creating independent entities responsible for the real-time operation of the distribution grid to manage the growing complexity of DERs. However, any such model must be adapted to the Indian context.

Ultimately, India's journey to net zero requires more than just top-down federal targets. It requires building capacity at the state level, empowering regulators to make politically difficult but economically necessary decisions, and engaging in a broader public dialogue about the costs and benefits of the energy transition. The tension between central ambition and state-level reality will continue to define the future of India's power sector.

Chapter 22: Distinctive Regulatory Challenges in Developing Countries

By Debabrata Chattopadhyay and Vivien Foster

The Unfinished Agenda of Classical Regulation

While the regulatory discourse in OECD countries has shifted decisively towards the challenges of decarbonisation and net zero, for many low- and middle-income countries (LMICs), the more foundational agenda of classical power sector regulation remains a work in progress. The distinctive challenges faced by LMICs are shaped by weak regulatory governance, financially fragile utilities, and rapidly growing, often unserved, populations. These underlying weaknesses not only hinder the achievement of basic economic objectives like cost recovery and reliability but also create significant barriers to the clean energy transition.

Weak Regulatory Governance

Although regulatory agencies have been established in about two-thirds of LMICs, their effectiveness is often severely constrained. A recent global assessment found that while these regulators typically have a clear legal mandate, they perform poorly on transparency, predictability, accountability, and, most critically, institutional independence.

- **Lack of True Autonomy:** Close to half of power regulators in LMICs are effectively advisory bodies, lacking final decision-making authority over crucial areas like tariffs. Their recommendations are frequently overturned or ignored by government ministers, often for political reasons. The problem is exacerbated by the fact that most regulators are overseeing state-owned utilities, creating a fundamental conflict of interest where the state is both the owner and the regulator.
- **Capacity Constraints:** Many regulatory agencies, particularly in smaller and poorer nations, lack the human and financial resources to discharge their functions effectively. A recent survey in Africa found that almost half of the continent's regulators had a low level of institutional capacity, lacking sufficient technical experts in critical areas like financial modelling, economic analysis, and engineering.
- **The Gap Between Law and Practice:** There is often a significant divergence between the *de jure* rules on the books and the *de facto* regulatory practice. Political interference and weak enforcement mean that even well-designed regulations are often not implemented as intended.

Challenges Along the Electricity Supply Chain

These governance weaknesses manifest as persistent problems across the entire electricity supply chain.

- **Distribution:**
    - **Tariff Regulation:** Tariff setting is the most critical and most challenging regulatory function. Many LMICs lack a clear and predictable methodology for tariff reviews. Cost-of-service studies are rarely conducted, and automatic tariff indexation mechanisms to account for inflation are often absent or suspended. As a result, tariffs can remain frozen for long periods, leading to a chronic failure to achieve cost recovery. The case of **Egypt** is illustrative, where tariff increases

recommended by the regulator have been repeatedly deferred by the cabinet due to economic crises. In contrast, **Colombia** provides a positive example of a regulator (CREG) that has successfully implemented regular, five-year price controls, improving the financial sustainability of the sector.
    - **Quality of Service:** Quality of service regulation is severely underdeveloped. Little more than half of LMICs have any meaningful system in place. Technical performance standards are often absent, and financial penalties for poor service are rarely applied. This contributes to the extremely poor reliability seen in many LMICs, where system interruption indices (SAIDI and SAIFI) can be one or two orders of magnitude worse than in developed countries.
- **Transmission:**
    - **Regulatory Neglect:** Because most LMICs have not fully unbundled their power sectors, the specific regulation of transmission is often overlooked. Key frameworks for ensuring non-discriminatory third-party access and setting cost-reflective wheeling charges are frequently missing. This lack of clear rules and pricing discourages private investment in generation, as developers have no certainty about how they will get their power to the grid.
    - **Underinvestment and Inefficiency:** The lack of regulatory oversight and sound economic planning has led to chronic underinvestment in transmission infrastructure. Networks are often congested, ill-designed, and reliant on lower-voltage lines, leading to high losses and poor reliability. The case of **Nigeria**, which suffers from frequent national grid collapses, highlights the severe consequences of a weak transmission system.
- **Generation and Power Markets:**
    - **Stuck in Transition:** While most OECD countries have moved to competitive wholesale electricity markets, only about one in five LMICs has done so. The majority remain either vertically integrated monopolies or are stuck in a **single-buyer model**, where a state-owned utility buys power from independent power producers (IPPs).
    - **The PPA Trap:** The single-buyer model is often plagued by inefficient and rigid long-term **Power Purchase Agreements (PPAs)**. These contracts, often signed in haste to attract investment, can lock utilities into paying high prices for decades, with inflexible take-or-pay clauses that prevent the dispatch of cheaper power sources, including new renewables. This legacy of expensive PPAs is a major barrier to market liquidity and further reform. The experience of the **South African Power Pool (SAPP)** shows that even in a regional market, trading volumes can remain extremely low when the bulk of generation is tied up in bilateral contracts.

Regulating for Net Zero in the LMIC Context

The transition to net zero presents an additional layer of complexity on top of these foundational challenges. While there has been a significant uptake of policies to support renewable energy across the developing world, the path is difficult.

- **Indirect Barriers:** The weaknesses in classical regulation directly impede the clean energy transition. The lack of creditworthy utilities makes it difficult to attract private investment in renewables. The absence of robust transmission grids and clear access rules strands renewable resources in remote areas. The lack of frameworks for ancillary services makes it difficult to manage the intermittency of wind and solar.
- **Success with Renewable Auctions:** Despite these challenges, the most significant positive story has been the successful use of **renewable energy auctions**. Many LMICs, including Brazil, India, and South Africa, have used competitive auctions to procure large volumes of renewable energy at record-low prices. While these auctions are not without pitfalls—such as the risk of "winner's curse" leading to project delays or cancellations—well-designed auctions with strong pre-qualification requirements and penalties for non-compliance have proven to be a highly effective tool.

Energy Efficiency and Coal Retirement: Progress in regulating for energy efficiency has been slower, with financing mechanisms being a particularly weak area. The challenge of phasing out existing fossil-fuel plants is immense, as LMICs are home to 80% of the world's coal plants. Innovative mechanisms are being explored, such as the Asian Development Bank's **Energy Transition Mechanism (ETM)**, which proposes to buy out coal plants for early retirement, and the World Bank's **Accelerating Coal Transition (ACT)** initiative, which focuses on repurposing coal plant sites for renewable energy.

Conclusion: A Long Road Ahead

For developing countries, the road to a modern, clean, and reliable power sector is long and challenging. The priority must be to strengthen the foundations of classical regulation: building independent and capable regulatory institutions, establishing predictable and cost-reflective tariff regimes, and creating the basic market frameworks that can attract investment and drive efficiency. Without these building blocks, the ambitious goals of the clean energy transition will remain out of reach. While policy-driven measures like renewable energy auctions can achieve remarkable success, sustainable, long-term decarbonisation will require a power sector that is built on sound regulatory and market principles.