COMPARATIVE REVIEW OF GLOBAL APPROACHES TO ELECTRICITY TARIFF SETTING: POLICY IMPLICATIONS FOR SOUTH AFRICA

SHIRLEY SALVOLDI

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Definitions

Average demand	The average rate at which electricity is consumed over a period (e.g. daily, monthly, annually), that is total consumption divided by time.
Excess demand	How much demand exceeds a baseline or threshold; can refer to demand beyond normal or expected load
Coincident-peak (CP)	The maximum demand that a load places on a system at the same time the system itself experiences its maximum demand.
Non-Coincident Demand (NCD) or Non-Coincident Peak Load	A customer's maximum energy demand during a billing period or a year, even if it is different from the time of the system peak demand.
Spot price	The system marginal price in a wholesale market

Abbreviations

CoS or CtS	Cost of supply or cost to serve
CP	Coincident peak
CPI	Consumer price index
ERA	Electricity regulation act 2006 (as amended)
ERTSA	Eskom Retail Tariff and Structural Adjustment
IBT	Inclining block rate tariff
LRMC	Long run marginal cost
MYPD	Multi Year Price Determination
NERSA	National Energy Regulator of South Africa
NCP	Non coincident peak
NTCSA	National Transmission Company of South Africa
O&M	Operating and maintenance
PBR	Performance based regulation
PV	Photo voltaic
RIIO	Revenue = Incentives + Innovation + Outputs
RoR	Rate of return
RPI	Retail price index
SRMC	Short run marginal cost
TOU	Time-of-use
WACC	Weighted average cost of capital

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Introduction and summary of key issues

This report reviews global approaches to electricity tariff design, focusing on cost of supply studies and other methods across various regulatory and market contexts. It examines current trends, technological impacts, cost drivers, affordability, tariff structures and customer categories, highlighting how these challenges are addressed in different countries.

The report concludes with recommendations for improving cost of supply practices in South Africa to support the goal of effective and efficient electricity tariff structures.

Cost of supply (CoS) or cost-to-serve (CtS) studies are the standard basis for electricity tariff design worldwide, though their application varies with local policies and regulations. In regulated markets (e.g., USA, Canada, South Africa, Brazil, EU), CoS/CtS is the default approach, while reforming or developing markets use it partially, often alongside tariff subsidies. Market-based systems depend on CoS for network related(wires infrastructure) tariffs, but energy purchase prices are market-driven.

Cost of supply is sometimes used as a term to justify a revenue build up from costs, but more accurately it deals with allocation of costs (or revenue) and sometimes - as in the National Energy Regulator of South Africa (NERSA) Cost of Supply Framework (NERSA, Cost of Supply Framework, 2020) - it combines both.

A CoS study (also called cost of service study) for electricity tariffs is a structured analysis used by utilities and regulators to determine how much it costs to provide electricity to different categories of customers (residential, commercial, industrial, municipalities, etc.). The results from the study guides tariff design so that prices better reflect the underlying cost of serving each category of customers.

The purpose of a CoS study is:

- To ensure fairness and transparency in electricity pricing.
- To align tariffs with the real cost drivers of supplying the service (including generation, transmission, distribution and customer service).
- To provide regulators with a rational basis for approving tariff applications from service providers.
- To prevent unintended cross-subsidisation, where one group of customers pays more than their fair share to cover the costs of another (unless such subsidisation is a clear policy objective).

The steps required for a CoS study and tariff design are:

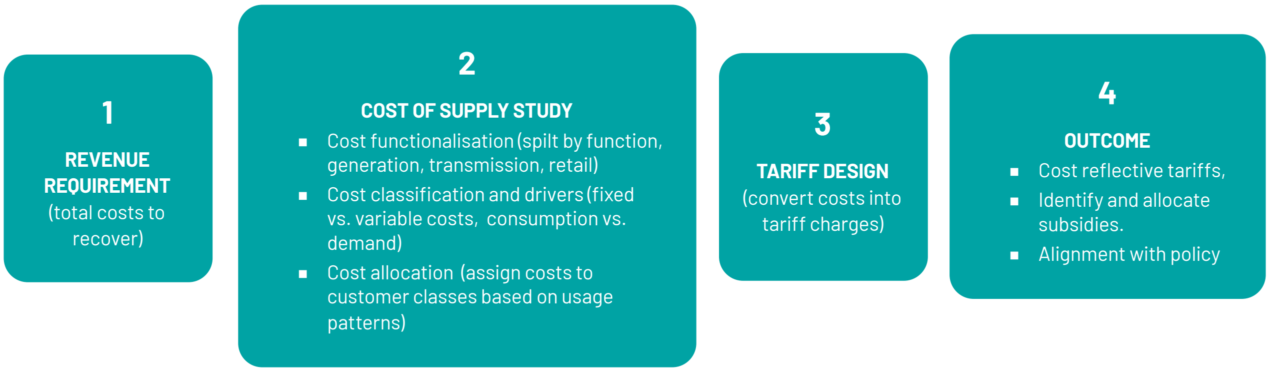

Figure 1: Steps followed in a CoS study

A CoS study-based process resulting in tariff setting involves:

1. **Determining the revenue requirement:** what is the total amount of revenue that a utility is required (or permitted) by regulatory authorities to recover in order to cover operating expenses, depreciation, taxes, an authorised return on assets, and other costs deemed recoverable. Various methodologies are utilised internationally to determine the applicable revenue requirement. The revenue requirement process includes determining the aggregate costs of supplying the service to all customers.

2. **CoS study (detailed classification and allocation of aggregate costs):**
   a. Cost functionalisation – splitting costs into broad functions: generation (or energy purchases), transmission, distribution, customer service, and administration.
   b. Cost classification – identifying which costs are fixed (do not change with electricity usage such as capacity) and which are variable (linked to energy consumed, demand, or time of use).
   c. Cost allocation – assigning costs to different customer classes based on how they use the electricity system. For example:
      - Residential users may drive higher peak demand (air conditioners, evening load).
      - Industrial users may need high voltage supply but offer steady demand.
      - Rural customers may require more network infrastructure per unit of demand.

The most detailed part of a cost of supply study is splitting the distribution costs among customers based on factors such as voltage, demand, losses and location.

3. **Tariff Design** – translating allocated costs into tariffs that that are as cost-reflective as possible, promote efficiency, are equitable considering policy objectives (affordability, competitiveness, environmental goals) and technology such as solar PV and batteries. This stage is challenging because achieving all the objectives mentioned is not always possible and relies more on art than the previous, more scientific steps. Politics and policy (national or local) also play a role before proposing final tariffs and when regulators make decisions

4. The **outcome** of a CoS Study should therefore result in:
   - Identification of the true and total cost to serve each customer category.
   - A benchmark for cost-reflective tariffs (i.e. ensuring that prices are aligned to actual service costs).
   - Highlighting of cross-subsidies (for example, households may be paying below true cost and other customers pay above true cost to balance this).
   - A good basis for tariff reform (for example, time-of-use tariffs, demand charges, lifeline tariffs, solar uptake).

This report outlines the details of each of these steps in the COS study and tariff design process, including comparative international regulatory approaches, and the implications for tariff design in South Africa.

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Revenue requirement

The revenue requirement process, as depicted in Figure 1 above, precedes detailed cost allocation and electricity tariff design. Regulators must always determine a revenue requirement in the presence of monopoly services, such as transmission and distribution operations, and this approach may also apply where generation is regulated or partially regulated within a market environment. Additionally, the process can include energy purchases that need to be recovered from non-contestable customers - those who do not have a choice of service provider. The aim of the revenue requirement process is to calculate the maximum revenue that can be recovered through tariffs to cover "prudent costs", under the applicable regulatory framework.

This revenue requirement step may be included as an integral part of a cost of supply study, such as the NERSA Cost of Supply Framework for distributors (NERSA, 2020) or conducted separately using the Multi Year Price Determination (MYPD) methodology (NERSA, 2016) for Eskom. In this report, revenue determination and cost allocation are discussed as separate processes.

2.1. Rate-of-return and prudency of costs

Several models are used globally to calculate revenue requirements. This section outlines the concepts of rate of return and cost prudency as they relate to these models.

2.1.1 Rate-of-return

In regulated utilities, "fair return" is the approved return on investments that can be included in tariffs, ensuring rates are neither excessive nor insufficient. The aim is to maintain a balanced approach that:

- Compensates the utility enough so they are willing to invest and be able to attract capital.
- Protects consumers from excessive prices or excessive monopoly profits.
- Maintains service quality, system reliability, and long-term viability through ensuring sufficient funding for infrastructure maintenance and investment.

Regulated utilities typically earn lower, but more predictable returns, while unregulated firms typically earn higher, but riskier returns, for the following reasons:

- Regulators generally aim to ensure that a utility can recover costs (including capital), so investors accept a lower return in exchange for that predictability.
- Utilities may have guaranteed customers, no market competition, and cost recovery mechanisms (pass-through for fuel, inflation indexation) and so are relatively low-risk.
- Regulators use a formula linked to market data and peer utilities, rather than to speculative investor expectations.
- Return must balance the requirement of "sufficient to attract capital" against "not excessive to consumers" to be considered reasonable.

The permitted rate of return is usually based on the weighted cost of capital (WACC) on an asset rate base value, both of which must be approved by a regulator. The rate of return is meant to recover a utility's:

- Cost of debt
- Cost of stock
- Cost of equity

The permitted rate of return is applied to the value of the regulated asset base and the determination of the asset base, using a regulatory formula, such a replacement cost of assets depreciated on useful life and technology.

The ***Electric cost allocation for a new era*** manual by Lazar (2020) explains that regulators typically apply a uniform permitted rate of return across all utility investments and customer classes, (similar to the method used for by NERSA for Eskom under current MYPD 6 revenue decision). However, due to an increasingly competitive electricity landscape this uniform approach may no longer be appropriate because certain assets, like generation, carry greater risk than others, such as distribution. Higher risk should be balanced with higher rates of return on assets. Additionally, since customer classes use assets differently, their required rates of return also vary accordingly. Differential rates can be set by adjusting equity, debt, or capital structures for varying assets and risk levels.

"Electricity Regulation In the US: A guide, 2nd edition" (Lazar J. , 2016) states:

> *"the rate base is the total of all long-lived investments made by the utility to serve consumers, net of accumulated depreciation. It includes buildings, power plants, fleet vehicles, office furniture, poles, wires, transformers, pipes, computers, and computer software."*

As a general regulatory rule, utilities should only add used and useful completed, and prudently incurred, investments to the rate base. During asset construction they can also accumulate an allowance for funds used, so once these assets are in service they earn a return on both their investment and the construction carrying costs.

2.1.2 Prudency of costs

On the burden of proof, the utility is required to provide evidence to convince their regulator that a cost or investment is reasonable, prudent, and recoverable, otherwise, those costs may be excluded. "Prudence" is shown where a capably managed utility follows a course of conduct considering existing and reasonably known circumstances. Prudency and reasonable should mean the same and include both forecast and committed costs.

However, as Lazar (2016) points out, a utility *"often enjoys **presumption** of use and usefulness, and prudence in the absence of evidence to refute it."* (our emphasis).

NERSA has published a guideline for prudency assessments (NERSA, Guidelines for prudency assessment, 2018) which provides the following for evaluating the prudency of capital expenditures.

- **Necessity**: Facilities must promote sustainable development and meet demand forecasts.
- **Reasonableness**: Costs must be justifiable and benchmarked against industry standards.
- **Best Interest**: Decisions should benefit both the utility and its customers.
- **Good Practice**: Costs must align with prevailing market conditions.
- **Due Care**: Evidence of sound business practices must be provided.
- **Asset Use**: Assets must be operational to be included in revenue calculation.

The above also provides the following guidelines for assessing the prudency of operating and maintenance costs:

- **Good Practice**: Costs should align with industry standards for efficient operations.
- **Reasonableness**: Expenditures must be justified based on known conditions at the time.
- **Due Care**: Decision-makers must demonstrate required skills and adherence to internal procedures.

Regulators face significant challenges when assessing actual prudency of utility costs; in deciding if investments or expenditures were reasonable and therefore which costs may be passed on to consumers. The effectiveness of their ability to accurately and objectively assess prudency is undermined by the following:

Information asymmetry / knowledge disadvantage

- Utilities often have much more detailed internal data (engineering studies, project plans, risk records) than they make available to regulators.
- Regulators frequently have to rely on incomplete or outdated information, making prudency assessments harder.

Resource and capacity constraints

- Regulatory bodies may lack sufficient staff, technical experts, or budget to deeply audit large capital projects, or high numbers of cost studies.[1]
- In particular, complex projects (e.g. power plants, transmission lines, renewables) require specialised engineering and cost-estimation skills to interrogate cost submissions, which skills are not always available in regulatory agencies.

Regulatory lag, political pressures, and capture

- Because cost applications are periodic, some imprudent costs may be masked by inflation adjustments.
- Regulators are not always independent of political forces, and can face pressure from government or utilities to approve large projects, irrespective of imprudent costs.
- Regulatory capture occurs where is there is undue influence by regulated firms over the regulator, undermining regulatory objectivity.

Hindsight bias and ex-post evaluation pitfalls

- Regulators sometimes fall into hindsight traps. Prudence reviews must focus on what was knowable at the time of commitment, not later information.
- Projects with cost overruns or demand shortfalls may be judged harshly, even if a reasonable decision was made initially.

Discretion, subjectivity and lack of standardisation

- Many prudence assessments rest on subjective judgment calls such as technology choices, and may produce inconsistent outcomes.
- Transparency, predictability, and consistency are often criticised as low in prudence reviews. In some jurisdictions, stakeholders question the clarity of regulatory decisions.
- Not all cost applications are subject to full prudence review—some costs are auto-pass-through or exempt.

The following table gives an overview of different examples of prudency reviews and the policy implications of each.

1 There are 167 municipal electricity distributors in South Africa

Table 1: Global examples of prudency review outcomes and policy implications

Review	Result	Policy implication
United States		
Shoreham Nuclear Plant (LILCO, NY): New York Public Service Commission staff sought to exclude ~US$1.5 bn from rate base in a prudence inquiry tied to Shoreham's ballooning costs; extensive litigation followed. (Commission N. Y., 1983)	**Qualified success**: Aggressive prudence scrutiny ultimately prevented full recovery of imprudent/unused nuclear investment, but only after years of litigation and public cost.	Prudence reviews can impose substantial disallowances, but require deep evidentiary records and can be protracted; nuclear megaprojects amplify information asymmetry and hindsight risks. (Rodgers, 1985)
United Kingdom		
Western HVDC Link delay (National Grid Electricity Transmission & SP Transmission Ltd): Ofgem secured £158 m consumer redress for a ~2-year delay; closed its investigation via alternative action. (OFGEM, £158 million redress for two-year delay to major 'Western Link' subsea cable, 2021) Shetland HVDC Link (SSEN - Scottish and Southern Electricity Networks): Ofgem disallowed costs (e.g., ~£0.2 m on converter station scope) after detailed project assessment. (OFGEM, Shetland HVDC Link - Project Assessment Decision, 2021)	**Success**: Clear, targeted ex-post penalties/disallowances for delays and inefficient spend, with transparent decisions.	UK practice shows effective, surgical cost control within a total expenditure (TOTEX*)/PBR regime; relies on project-level assessments and redress/penalty tools rather than broad "prudence" doctrines. *A TOTEX regime is a regulatory approach that treats capital (CAPEX) and operating (OPEX) expenditure together, rather than regulating them separately.
South Africa		
RCA / Eskom court reviews: Courts have set aside/criticised NERSA determinations and processing of Eskom's revenue/RCAs, forcing re-looks or settlements (e.g., 2020 High Court ruling; later 2025 NERSA-Eskom settlement pending court order).	**Mixed / failure in parts**: Judicial reversals signal procedural/ analytical weaknesses that undermine prudence efficacy; later settlements aim to stabilise outcomes.	Robust prudence hinges on timely, well-reasoned RCA decisions and litigation-proof process; absent that, court intervention erodes regulatory credibility and delays cost certainty.
India		
CERC (Central Electricity Regulatory Commission) capex prudence checks: CERC has disallowed additional capital expenditure where utilities could not justify claims (e.g., APTEL (Appellate Tribunal for Electricity) 2023 judgment upholding disallowance linked to "special allowance" coverage; multiple CERC orders rely on explicit "prudence check" clauses). (Order of the CERC in Petition No. 291/ GT/2014 dated 23.08.2016,)	**Success (case-by-case)**: Regular, rule-based prudence checks on capital cost and change-in-law claims; appellate review provides due-process guardrails.	India demonstrates value of codified prudence criteria (e.g., Tariff Regulations) and appellate oversight (APTEL) to keep decisions consistent and reviewable. (Petition for approval of tariff of Talcher Super Thermal Power Station, Stage-II , 2023)

2.2 Regulator models for the determination of revenue

Globally, there are a range of revenue determination models in use. Details of the most-commonly-used revenue models are set out below.

(In South Africa, Eskom uses NERSA's Multi Year Pricing Determination (MYPD) methodology (NERSA, 2016), which incorporates elements from multiple approaches, while municipal distributors apply the NERSA Cost of Supply Framework (NERSA, 2020), a simplified version of MYPD with cost allocation to different categories of customer.)

2.2.1 Rate-of-return regulation (traditional model)

In this model, the regulator sets tariffs to cover the utility's prudently incurred costs plus a fair return on investment (capital). The utility calculates:

- its future prudent costs (operations and maintenance, fuel, depreciation, return on capital/assets based on weighted average cost of capital, etc.),
- its asset base; and
- a return on assets (which may differ depending on the risk and type of asset).

and submits this data to the regulator.

The revenue requirement decision is, therefore, based on the Regulator's view on prudent costs plus their view of the asset base and a what is determined to be a fair return on these assets. This method is often used in vertically integrated monopolies (generation, transmission, distribution).

The Pros and Cons of rate-of-return regulation can be summarised as follows:

Table 2: Pros and Cons of rate-of-return regulation

Pros	Cons
▪ Ensures utility financial stability and cost recovery. ▪ Provides certainty for investors (predictable returns). ▪ Straightforward methodology for regulators.	▪ Utilities may inflate asset values since profits are linked to the asset base. ▪ Encourages cost-padding (utilities pass inefficiencies to consumers) and relies on the Regulator to assess what are prudent costs. ▪ Regulatory capacity burden: requires detailed audits and frequent reviews. ▪ Can create uncertainty in prices if the utility is allowed by the regulator to claw prior year costs (for example, the NERSA Revenue Clearing Account (RCA) approach

Revenue Clearing Account (RCA)

A revenue clearing account, also referred to as a balancing account, a revenue balancing account, a true-up or an adjustment account, is a monitoring and tracking mechanism employed by regulators for regulated utilities to reconcile differences between authorised cost recovery determined in a revenue decision and the actual revenue or costs incurred following that decision.

This adjustment mechanism enables either the utility or the regulator to modify future tariffs by considering prudent expenditure, loss of sales, or unforeseen circumstances beyond the utility's control (for example, the impact of COVID-19). Conversely, if there is an over-recovery resulting in additional revenue, this excess will be offset through lower tariff increases in subsequent periods.

In South Africa, Eskom's RCA applications have become material given forecasting differences and increased costs, with NERSA typically not approving the full amount requested by Eskom. They have triggered public debate and litigation around timing, transparency, and regulatory process.

Globally, RCA-type mechanisms do work to bridge forecast error and costs outside of the utility's control if they are narrowly scoped, audited, and cleared promptly. Where balances are allowed to accumulate or the process lacks clarity, the result is tariff shocks, litigation, and credibility loss.

There are benefits associated with the use of an RCA, but also risks and challenges as summarised in the table below:

Table 3: Risks and challenges of An RCA mechanism

Benefits	Challenges
▪ Helps utilities maintain financial stability between rate cases ▪ Improves fairness by aligning actual versus forecasted performance ▪ Enhances transparency by isolating variance components ▪ The clearing account can show exactly how much variance is due to volumes, rate differences, cost changes, forecast errors, etc. ▪ Supports universal service and affordability ▪ Simple and transparent formula	▪ If poorly audited, the clearing account may become a vehicle for passing imprudent costs to consumers (and thus possibly be subject to litigation by consumers). ▪ Increases regulatory complexity and requires designing proper rules, triggers and timing. Has cash-flow implications if there are prudent costs incurred that are recovered in later years. ▪ Utilities may become lax in forecasting or cost control if they expect clearing protection ▪ Requires proper assessment, but can create instability in tariff prices if variances are large ▪ Weak incentives for efficiency and limited innovation incentives ▪ Information asymmetry and regulatory burden where regulators may struggle to determine prudent cost

How have different countries approached the challenge of improving the outcomes of rate-of-return regulation? The table below sets out some examples of successful initiatives designed to achieve particular regulatory goals, focusing on the observed outcomes and policy implications of each of these.

Table 4: Global examples of successful rate-of-return regulation to improve outcomes

Example	Observed outcome	Policy implication
REGULATORY GOAL: PROVIDE INVESTMENT CERTAINTY AND FINANCIAL STABILITY		
United States – State Public Utility Commissions (PUCs)	Utilities recover prudently incurred costs plus an allowed rate of return on their regulated asset base. Stable earnings attracted long-term capital and supported infrastructure expansion throughout the 20th century.	RoR ensures predictable revenue and investor confidence, especially for capital-intensive utilities.
Canada – National Energy Board (NEB) & Provincial Regulators	Pipeline and electricity utilities financed through stable allowed returns based on WACC.	Consistent returns encouraged private financing of transmission and pipelines under long asset lives.
Japan – Electricity & Gas Utility Regulation (pre-liberalisation)	Government-set tariffs based on accounting rate of return; ensured utility solvency and system reliability for decades.	Suitable for monopolies during early development stages or where service reliability is paramount.
REGULATORY GOAL: SUPPORT UNIVERSAL SERVICE AND AFFORDABILITY		
France – EDF under Cost-plus Regulation (pre-1990s)	State-owned utility achieved near-universal electrification under regulated returns.	RoR models can successfully deliver public service objectives when aligned with policy goals.
South Korea – KEPCO (before partial market reform)	Allowed returns incentivised large-scale investment and expansion of generation and grid capacity.	RoR frameworks can mobilise rapid infrastructure growth under central planning.
China – Grid Companies under NDRC (National Development and Reform Commission) regulation	Transmission and distribution rates set via approved asset base and return allowance.	RoR effective for maintaining grid expansion and avoiding tariff shocks in developing systems.

Example	Observed outcome	Policy implication
REGULATORY GOAL: SIMPLE AND TRANSPARENT TO ADMINISTER		
India – CERC/SERC Tariff Determinations for Regulated Assets	Tariffs set on cost-plus basis: operating costs + depreciation + approved return on equity (typically 14–16%).	Simplicity allows use in capacity-constrained regulatory environments.
South Africa – Eskom (historic regulatory model)	MYPD iterations closely resemble RoR regulation for capital recovery.	Easy to apply when data and benchmarking are limited.
Philippines – National Power Corporation (NPC), pre-reform)	Tariffs reflected cost-of-service with allowed returns on assets, ensuring stable expansion pre-market liberalisation.	Useful transitional model before moving to performance-based regulation.

In contrast, the table below sets out examples of rate-of-return regulation that had a negative result, and the policy implications of each of these regulatory failures.

Table 5: Global examples of less successful rate-of-return regulation outcomes

Example	Observed outcome	Policy implication
RESULT: WEAK INCENTIVES FOR EFFICIENCY		
United States – Pre-1980s experience	Overcapitalisation occurred ("gold plating") as utilities earned higher returns by expanding their regulated asset base.	Without incentive overlays, RoR encourages excessive capital spending and inefficiency.
India – Cost-plus generation tariffs	Generators had little incentive to reduce costs or improve heat rate since all prudent costs were pass-through.	Combine RoR with performance or efficiency benchmarks to prevent cost inflation.
Brazil – pre-1990s state utilities	Guaranteed returns encouraged overstaffing and high operating costs before liberalisation.	Regular cost audits and benchmarking are essential to control inefficiency.
RESULT: REGULATORY LAG AND COST PASS-THROUGH ISSUES		
United States – 1970s fuel price shocks	Delayed rate adjustments caused financial distress for utilities as costs rose faster than regulated revenues.	Automatic pass-through mechanisms or fuel cost clauses are needed for uncontrollable costs.
South Africa – Eskom (late 2000s)	Regulatory delays under cost-plus pricing led to liquidity problems and deferred maintenance.	Timely tariff reviews and predictable update cycles maintain financial stability.
Mexico – CFE (Comisión Federal de Electricidad state-owned, vertically integrated electricity utility) before market reform	Inflation and fuel costs outpaced tariff revisions, leading to chronic under-recovery.	Indexation and periodic tariff reviews sustain cost-reflectivity.
RESULT: INFORMATION ASYMMETRY AND REGULATORY BURDEN		
UK – Central Electricity Generating Board the state-owned, vertically integrated electricity utility of England and Wales from 1957 until 1990 era (pre-privatisation)	Regulators struggled to verify "prudence" of capital and O&M expenditures, leading to inefficiency and overstaffing.	Detailed accounting reviews increase administrative burden; modern regulators need cost benchmarking.
Indonesia – PLN (Perusahaan Listrik Negara, the State Electricity Company) tariff regulation	Government-set cost base lacked transparency and independent audit, creating hidden cross-subsidies.	Transparency and third-party audits build credibility.

Example	Observed outcome	Policy implication
Nigeria – NEPA (former state-owned monopoly utility from 1972 to 2005) (pre-reform)	Politically influenced cost-plus tariff approvals undermined performance and investment.	RoR frameworks fail when regulators lack independence or capacity.
RESULT: LIMITED INNOVATION INCENTIVES		
France and Japan – Cost-plus regimes (pre-1990s)	Utilities prioritised system reliability and expansion but lagged in digitalisation and demand-side innovation.	Add research and development allowances or performance-based rewards to drive innovation.
United States – Pre-PBR transition	Innovation in renewables, demand response, and grid modernisation was slow under pure RoR.	Shifting to hybrid models (e.g., decoupling, PBR) fosters innovation.
South Korea – KEPCO (pre-market)	Centralised RoR planning emphasised expansion over efficiency or smart-grid technology.	Pair RoR with innovation or quality-of-service incentives to modernise systems.

Key takeaways for rate-of-return as a revenue determination methodology are:

- Rate-of-return remains the foundation of modern regulation — it is still widely used for transmission and distribution utilities globally.
- However, it is best suited to natural monopolies, early-stage markets, and sectors needing stable investment frameworks.
- To avoid inefficiency, most regulators now combine rate-of-return with incentive elements (e.g., capex efficiency targets, service-quality penalties, or CPI–X indexing).
- Transparency, auditing, and prudency reviews are key to sustaining credibility and balancing cost recovery with public value.

2.2.2 Incentive based regulation: Price Cap/Revenue Cap - X

In this model, utilities are given a cap on prices or revenues, adjusted for inflation (RPI/CPI[2]) minus an efficiency factor (X). The Regulator sets a price cap (maximum tariffs) or revenue cap (total allowed revenue) for a multi-year period. This approach differs from traditional rate of return regulation by incentivising cost reduction, discouraging inefficiency, and providing multi-period price certainty for consumers.

The incentive-based regulation method promotes cost savings and innovation, by allowing utilities to retain efficiency gains above the level of X until the next reset. However, if X is set too high it may lead to under-investment.

In the NERSA MYPD methodology applied to Eskom (NERSA, 2016), there are service quality incentives with rewards/penalties that are applied according to the performance achieved by Eskom on the parameters set in the schemes. It is, however, not true incentive-based revenue regulation as it only deals with service quality and does not incentivise cost reduction through operational efficiency.

2 Retail Price index (RPI) includes mortgage interest and other housing costs, Consumer price index (CPI) does not. CPI tends to be lower than RPI because of differences in calculation methods. For regulatory purposes, many countries now use CPI – X instead of RPI – X.

The pros and cons of incentive-based regulation are summarised in the table below:

Table 6: Pros and cons of incentive-based regulation

Pros	Cons
▪ Strong incentives for efficiency: utilities keep efficiency savings until next reset. ▪ Predictable for customers (stable prices within review periods). ▪ Encourages innovation and cost control.	▪ Risk of underinvestment if efficiency targets are too aggressive. ▪ Information asymmetry: regulator may misjudge true efficiency potential. ▪ Can lead to cost-cutting that harms reliability or service quality in the interests of short-term profits

Some global examples of incentive-based regulation that have resulted in the above pros or cons (and the policy implications of each) are set out in the table below. The examples include regulated non-electricity sectors:

Table 7: Global examples of incentive-based regulation outcomes

Category	Example	Observed outcomes	Policy implication
Efficiency Incentives	**UK Power Networks (RIIO-ED1)**	Achieved >10% cost savings through automation and asset optimisation; retained profits until next reset.	Efficiency gains emerge when utilities can keep savings for a full control period.
Price Predictability	**Australian Energy Regulator (AER)**	CPI-X formula kept tariffs stable for five-year periods, reducing political volatility.	Multi-year caps enhance customer confidence and tariff stability.
Innovation & Cost Control	**Ofwat (UK Water)**	Companies invested in leakage-reduction and smart technologies, improving performance within price caps.	Output-linked incentives can foster innovation and service quality.
Underinvestment	**Railtrack (UK Rail, 1990s)**	Aggressive X targets led to deferred maintenance and an increase in accidents.	Overly tight X-factors can harm asset condition and public safety.
Information Asymmetry	**Ofgem RIIO-2 Appeal (UK, 2021)**	The Competition & Markets Authority revised Ofgem's efficiency assumptions, finding misjudged risk-return balance.	Regulators need credible benchmarking and engagement to set realistic X.
Quality Erosion	**Chile (CNE, 2000s)**	Utilities cut maintenance expenditure to meet cost targets, increasing outages until quality metrics were added.	Pair price caps with explicit reliability/ service KPIs.

Key takeaways for incentive-based regulation are:

- CPI–X regulation is effective, but targets must be calibrated correctly, within the context of the specific sector and the realistic ability of utilities to meet them.
- Success depends on balance between strong incentives but realistic efficiency targets.
- Integrating quality, transparency, and innovation metrics transforms CPI–X from a cost-cutting tool into a modern performance framework.

2.2.3 Performance-based regulation (PBR)

In the performance-based model, permitted revenues or returns are linked to selected performance targets (for example - reliability, customer satisfaction, emissions, decarbonisation). Utilities are rewarded or penalised depending on performance. This approach can be combined with rate of return regulation or incentive regulation. The MYPD applied to Eskom may be considered partially performance-based due to the service quality metrics implemented by NERSA.

The Pros and Cons of performance-based regulation are summarised in the table below:

Table 8: Pros and cons of performance-based regulation

Pros	Cons
▪ Aligns utility incentives with policy goals (for example, decarbonisation, customer service). ▪ Flexibility as it can be layered onto rate of return or incentive regulation. ▪ Encourages innovation and long-term planning.	▪ Designing robust performance metrics is complex. ▪ Risk of gaming or unintended consequences (utilities focusing only on measured metrics). ▪ Requires advanced regulatory capacity and data monitoring

Some global examples of performance-based regulation that have resulted in the above pros or cons (and the policy implications of each) are set out in the table below:

Table 9: Global examples of performance-based regulation (PBR) outcomes

Examples	Observed outcome	Policy implication
ALIGNS UTILITY INCENTIVES WITH POLICY GOALS		
New York, USA – "Reforming the Energy Vision" (REV) PBR framework	PBR ties utility earnings to carbon reduction, DER (distributed energy resource) integration, and customer engagement. Utilities like Con Edison can earn incentive "Earnings Adjustment Mechanisms" for achieving clean energy and reliability targets.	PBR can successfully align utility profit motives with decarbonisation and innovation if metrics are well-defined and backed by stable policy.
Hawaii, USA – Performance-Based Regulation (2021)	Replaced rate of return with PBR focused on renewable integration and affordability. Initial results show better control of O&M costs and more renewable grid connections.	PBR is an effective bridge between financial sustainability and climate targets in small isolated systems.
FLEXIBILITY (LAYERED ONTO RATE-OF-RETURN OR CPI-X)		
Ontario, Canada – Incentive Regulation Mechanism (IRM)	Combines CPI-X revenue cap with performance scorecards (reliability, customer service). Utilities retain cost efficiency gains but also face penalties for poor quality.	PBR is modular – it can sit atop existing regulatory models without full overhaul.
Australia – AER's Service Target Performance Incentive Scheme (STPIS)	Layered on CPI-X price caps. Rewards/ penalises networks for reliability and customer service relative to benchmarks.	Blending performance and price cap incentives balances efficiency with reliability – a "best of both worlds" model.
Chile – Distribution performance-based adjustments	PBR components complement benchmarking-based price caps by rewarding reliability (SAIDI/SAIFI) improvements.	Flexible integration possible even in developing markets, but only where quality data exist.

Examples	Observed outcome	Policy implication
ENCOURAGES INNOVATION AND LONG-TERM PLANNING		
UK – Ofgem RIIO "Innovation Stimulus Package"	Created funds like the Network Innovation Allowance (NIA) and Network Innovation Competition (NIC); led to >200 innovation projects in smart grids, EV integration, and storage.	Linking PBR to dedicated innovation funds promotes transformational projects without breaching efficiency caps.
California – PBR pilots (PG&E, SCE)	Allowed performance-based earnings for demand response, EV charging, and distributed resources.	PBR fosters cross-functional innovation (IT, operations, customer engagement) when risk-sharing is clear.
Denmark – Revenue-cap with innovation incentives (Energinet, DSOs)	Introduced innovation KPIs within revenue caps to support digitalisation and grid flexibility.	PBR works best when paired with long-term certainty (multi-year commitments).
DESIGNING ROBUST PERFORMANCE METRICS IS COMPLEX		
Ofgem RIIO-1 (2013–2021)	300+ output measures led to complexity and reporting burden, with stakeholders complaining of opacity and "metric overload."	Too many metrics dilute focus — simplicity and clarity are critical.
New York REV (2015–2022)	Some earnings mechanisms underutilised because performance metrics weren't clearly defined, or data were delayed.	Overly complex or vague KPIs delay incentives and frustrate utilities.
Mexico CRE (2015–2019)	Efforts to integrate service-quality PBR stalled due to inconsistent data and unclear methodology.	PBR needs data maturity and transparent formulas to function.
RISK OF GAMING OR UNINTENDED CONSEQUENCES		
US – California early PBR pilots (1990s)	Utilities focused narrowly on meeting numeric targets (e.g., outage minutes) rather than holistic reliability; some "managed" metrics instead of improving systems.	Performance must be broadly defined and independently verified to prevent gaming.
Chile (2000s)	Distributors reduced outage duration but not frequency, as only duration was measured.	Poorly designed metrics can shift behaviour toward optimising scores, not outcomes.
REQUIRES ADVANCED REGULATORY CAPACITY AND MONITORING		
Kenya / Nigeria PBR pilots	Regulators lacked consistent performance data and analytical tools to verify claims; utilities disputed outcomes.	Without data systems and independent verification, PBR collapses into "negotiated regulation."
Philippines – PBR Framework (ERC)	Initially improved transparency, but data/reporting requirements strained regulator capacity; delays in resets undermined credibility.	Successful PBR needs institutional and IT investment for data auditing and tracking.
Peru / Colombia	Performance adjustments worked for reliability but required ongoing recalibration due to evolving data accuracy.	Regulators must build capacity over time — PBR is not "set and forget."

Key takeaways for performance-based regulation are:

- Performance-Based Regulation works best when incentives are strong but simple, and metrics are measurable and transparent.
- Developing markets should phase in performance-based regulation gradually and in incrementally, focusing first on basic indicators such as reliability and customer service before adding factors like carbon and more advanced innovation indicators.
- Regulators must have the institutional capacity to monitor performance and to adapt indicators as required.
- A performance-based approach can be a powerful complement to effective regulation by aligning utility profits with performance (i.e. rewarding outcomes and not only inputs)

2.2.4 Multi-year regulation

For any of the models discussed in this chapter a regulatory choice can be made between annual tariff reviews or multi-year reviews (typically 3 to 8 years). In practice, most regulators use multi-year frameworks, but these may include "re-opener clauses" for inter-period reviews around the impact of costs outside of the utility's control, like fuel price spikes, inflation, volume, and unexpected demand changes.

The MYPD applied to Eskom is a muti-year approach (usually 3 years).

The Pros and Cons of multi-year regulation are summarised in the table below:

Table 10: Pros and cons of multi-year regulation

Pros	Cons
Regulatory certainty and stability ▪ Provides utilities with predictable revenues, which reduces investment risk. ▪ Encourages long-term planning and capital investment (grid upgrades, renewables integration).	▪ Tariffs are based on cost and demand forecasts for a fixed period. ▪ If forecasts are wrong for cost increases for events such as fuel prices, changes in volume and inflation, utilities may be under- or over-compensated. ▪ Allows for re-openers which can cause volatility and uncertainty in prices.
Efficiency incentives ▪ If utilities reduce costs below the forecast level, they keep the benefit until the next review. ▪ Creates stronger motivation to improve productivity and innovate	**Risk of windfall gains or losses** ▪ Utilities may reap excess profits if they outperform assumptions, or face financial stress if costs rise unexpectedly. ▪ Consumers may pay more than necessary until the next review
Reduced regulatory burden ▪ Less frequent tariff reviews lower administrative costs for both regulators and utilities. ▪ Allows regulators to focus on broader strategic oversight instead of constant rate cases	**Reduced flexibility** ▪ Harder to adjust tariffs quickly if conditions change, for example, an energy crisis or economic downturn. ▪ Political pressure may force mid-period interventions, undermining credibility
Encourages innovation and customer focus ▪ Longer cycles (e.g. UK's RIIO[3] with 8 years) give room for utilities to implement new technologies and service improvements.	**Regulatory complexity** ▪ Requires sophisticated benchmarking, inflation adjustments, and efficiency factors (like RPI-X or CPI-X). ▪ If poorly designed, can distort incentives such as encourage cost-cutting at expense of quality.

3 RIIO = Revenue = Incentives + Innovation + Outputs. Revenue that the network company is permitted to earn is linked not just to costs, but also includes: Incentives = financial rewards/penalties for efficiency and good performance; Innovation = encouraging smart grids, low-carbon integration, and new technologies; Outputs = measurable service outcomes like reliability, customer service, safety, and environmental performance.

Some global examples of multi-year regulation that have resulted in the above pros or cons (and the policy implications of each) are set out in the table below:

Table 11: Global examples of outcomes of multi-year regulation

Examples	Observed outcome	Policy implication
OUTCOME: ENCOURAGES LONG-TERM EFFICIENCY AND COST DISCIPLINE		
Australia – CPI-X network regulation (AER)	Over successive five-year control periods, electricity and gas networks improved productivity and reduced OPEX relative to inflation.	Predictable multi-year caps give firms time to plan cost reductions and efficiency projects without regulatory micromanagement.
UK – Ofgem Price Caps (1990s onwards)	Initial RPI-X regimes led to large early efficiency gains; companies retained savings until next reset.	Multi-year incentives work best when utilities can retain savings within a full period, and customers benefit later via lower baselines.
Peru – OSINERG Distribution Tariffs	Five-year tariff reviews drove sustained improvements in cost efficiency and service reliability.	Strong baseline setting and consistent resets sustain productivity growth over decades.
OUTCOME: PROMOTES REGULATORY STABILITY AND INVESTMENT CERTAINTY		
South Africa – NERSA MYPD (2006–present)	Multi-year price determinations provided predictable paths for Eskom's revenue requirement and investor planning.	Regulatory stability underpins financing; deviations should be limited to exceptional "re-openers."
India – Multi-Year Tariff (MYT) framework (CERC & SERCs)	Predictable tariff paths improved investor confidence and project bankability for IPPs and distribution companies.	Multi-year regulation improves investment climate by signalling transparent long-term rules and predictable risk allocation.
Brazil – ANEEL multi-year reviews	Periodic reviews and annual indexation enabled financial planning and lowered regulatory risk premiums.	Clear rules on inflation, pass-through, and quality factors are essential for stability.
OUTCOME: REDUCES REGULATORY BURDEN AND POLITICAL INTERFERENCE		
Ontario, Canada – Incentive Regulation Mechanism (IRM)	Annual reviews replaced with formula adjustments (CPI–X), freeing regulator resources and reducing politicisation.	Multi-year regulation simplifies oversight while maintaining accountability via periodic benchmarking.
Chile – Distribution price reviews every four years	Stable regulatory cycles reduced lobbying and disputes between utilities and government.	Clear review cycles depoliticise tariff decisions and focus debates on technical data, not politics.
OUTCOME: ENCOURAGES INNOVATION AND PERFORMANCE FOCUS		
UK – RIIO multi-year cycles (8 years)	Innovation funding and output incentives tied to long-term plans encouraged digitalisation and low-carbon technologies.	Longer regulatory horizons allow utilities to invest in transformation projects that need payback over multiple years.
Denmark – Revenue-cap with five-year resets	DSOs invested in automation and smart grids under predictable multi-year terms.	Innovation thrives when regulatory risk is low, and recovery periods are long.
OUTCOME: RISK OF FORECASTING ERRORS AND PRICE SHOCKS		
South Africa – Eskom MYPD & RCA adjustments	Forecasting errors (demand, fuel, IPP costs) led to large RCA balances and delayed recoveries.	MYR must include flexible "true-up" or pass-through mechanisms for uncontrollable costs.
Brazil – Early tariff reviews (2000s)	Macroeconomic volatility and FX swings created misalignments between actual and forecasted costs.	Automatic indexation and exchange-rate adjustment clauses are critical safeguards.
India – MYT for distribution (some SERCs)	Volume and loss forecasts proved overly optimistic; shortfalls created financial stress.	Regulators should calibrate multi-year regulation assumptions with robust data and mid-term corrections.

Examples	Observed outcome	Policy implication
OUTCOME: POTENTIAL UNDER- OR OVER-RECOVERY BETWEEN REVIEWS		
UK – Early RPI-X electricity cap (1990s)	Rapid efficiency gains initially yielded windfall profits; later corrections reversed some incentives.	Calibrate X factors conservatively and revisit at reset to maintain fairness.
Nigeria – Multi-Year Tariff Order framework	Aggressive loss-reduction and efficiency assumptions left distributors unable to recover costs, triggering liquidity crises.	Setting unrealistic multi-year targets undermines credibility; must reflect local constraints.
Chile – Reference company benchmarking	Under-recovery occurred for smaller utilities where modelled "efficient" costs underestimated reality.	Use multiple benchmarking methods to avoid bias in standard-cost models.
OUTCOME: REGULATORY LAG AND DATA UNCERTAINTY		
Australia – Electricity network resets	Data gaps delayed resets; interim arrangements required.	Strong data collection and planning systems reduce lag and maintain regulatory credibility.
Kenya – Draft Multi-Year Tariff (ERC Energy Regulatory Commission (ERC)(renamed EPRA under the 2019 Energy Act)	Implementation stalled due to inadequate data and political delays.	Multi-year regulation requires mature data and institutional independence.
OUTCOME: COMPLEXITY OF ALIGNING WITH QUALITY AND POLICY GOALS		
UK – RIIO-1 experience	300+ output and performance metrics led to administrative burden and unclear focus.	Simpler, outcome-based metrics improve transparency and effectiveness.
Philippines – MYR PBR Framework (ERC)	While transparent, the system became complex, creating disputes and delayed true-ups.	Keep multi-year regulation design straightforward—too many moving parts reduce efficiency.

Key takeaways for multi-year regulation are:

- Predictable multi-year terms support investment and efficiency.
- Flexibility is essential. This can be achieved by allowing true-up or RCA-type mechanisms for uncontrollable costs or events.
- Success in is driven by data maturity, strong forecasting capacity in entities, strong auditing capacity within the regulator, and transparency.
- Conservative, evidence-based cost-factors sustain a long-term balance between investor and consumer requirements.

2.2.5 Regulation to achieve social and/or political goals

In this approach, permitted revenue (or tariffs – which will deliver a permitted revenue outcome) are set by the regulator in order to support goals such as affordability or protection of a sector. That is, at least part of the aim of regulation is to pursue social or political goals rather than just strict cost recovery. This approach may be combined any of the other methodologies discussed above and could involve tools such as overall subsidies (to address the gap between permitted and required revenue) or cross-subsidisation between tariffs for different customers.

Tariffs established in this manner can promote equity and inclusive access to services. However, if this is not accompanied by transparent subsidy frameworks and accurate cost recovery strategies, they may result in financial imbalances, underinvestment, unsustainable cross-subsidies that unfairly burden some customers, diminished service quality, and lower customer satisfaction. A protracted period of under-recovery of costs may lead to financial distress of utilities.

Some countries have combined socially or politically regulated tariffs with performance or incentive mechanisms to create a dual-layer regulatory structure:

- one layer for utility cost recovery (ensuring efficiency and financial sustainability), and
- another layer for consumer tariff setting (addressing affordability or political objectives).

This approach preserves economic discipline while allowing governments to achieve social goals without distorting cost signals or utility solvency. **The most resilient models decouple efficiency regulation from social pricing**: regulators determine efficient costs and returns, while governments manage affordability through transparent fiscal mechanisms that do not distort the cost recovery model.

The Pros and Cons of socially/politically determined regulation are:

Table 12: Pros and cons of socially/politically determined regulation

Pros	Cons
▪ Politically popular in contexts with inequality or poverty. ▪ Helps manage inflationary and political pressures. ▪ Creates cross-subsidies that distort consumption (creating wastage and inefficient and uneconomic price signals) and investment signals.	▪ Discourages private investment in power sector. ▪ Cross-subsidies do not always reach the intended recipients or are not correctly targeted ▪ Under-recovery of revenue leading to poor service delivery

Some global examples of multi-year regulation that have resulted in the above pros or cons (and the policy implications of each) are set out in the table below:

Table 13: Global examples of socially or politically set tariffs and policy implications

Country / Scheme	How the separation works	Outcome	Policy implication
Brazil – Tarifa Social + ANEEL Cost-Reflective Tariffs	ANEEL determines efficient cost-based tariffs for all distributors. The **Social Tariff** discounts for low-income users are **funded via the CDE (Energy Development Account)** — not by distorting cost allocation.	Maintains efficiency incentives and utility solvency while achieving social protection.	Clear institutional separation between regulator (efficiency) and government (subsidy).
Chile – Distribution Tariff + Subsidy Law (2014)	Tariffs set by model "efficient firm" methodology (benchmarking). Low-income consumers receive targeted subsidies from the fiscal budget via municipalities.	Tariffs remain efficiency-driven, while equity is handled outside the cost-recovery framework.	Benchmark-based tariff design can coexist with targeted social transfers.
South Africa – NERSA Cost-Reflective Tariffs + Free Basic Electricity (FBE)	Eskom and municipalities recover costs via NERSA-approved tariffs; FBE provides 50–60 kWh/month free to indigent households, funded by the national fiscus.	Utilities stay financially viable while the poor receive direct benefit.	Separate subsidy funding avoids undermining efficiency regulation.
India – CERC/SERC Cost-Plus Tariffs + Cross-Subsidy & DBT Pilots	Cost-reflective tariffs for utilities are maintained; low-income or agricultural users are cross-subsidised, increasingly via **Direct Benefit Transfers (DBT)** instead of embedded tariff gaps.	Reduces financial stress on utilities and improves subsidy transparency.	Gradual decoupling of subsidy delivery from tariff setting preserves efficiency incentives.
United Kingdom – Cost-Based Price Controls + Energy Price Guarantee (2022)	Ofgem maintains efficiency-based RIIO price caps. During the 2022 energy crisis, the government capped consumer bills and reimbursed suppliers for the difference.	Cost efficiency framework remained intact; affordability managed fiscally.	Temporary separation during crises can protect consumers without distorting regulatory signals.
Philippines – PBR Tariffs + Lifeline Discounts	ERC determines efficient tariffs via PBR; government mandates social discounts compensated through the Universal Charge mechanism.	Maintains investment climate and social affordability.	Transparent cost tracking and compensation prevent cross-subsidy leakage.

Politically or socially set tariffs can lead to significant fiscal support being required. International examples of such bailout interventions are shown in the next table:

Table 14: Common bailout patterns

Country / Region	What happened?	Bailout form	Key lesson
South Africa – Eskom	Below-cost tariffs for years, plus lower than requested NERSA approvals.	>R250 billion in government guarantees and direct equity injections (2019–2024).	Tariff suppression inevitably leads to fiscal rescue.
Nigeria – DisCos (Distribution Companies) under multi-year tariffs	Politically frozen tariffs + inflated losses; DisCos unable to recover even operating costs.	Federal government intervention through the Power Sector Recovery Program and >₦1 trillion liquidity support.	Political tariff control shifted deficit to national budget.
Ghana (2014–2017)	Government delayed cost-reflective tariff increases during crisis years.	State assumed utility debts, negotiated IPP arrears, and securitised losses via bonds.	Bailout financed through levies after tariff populism.
Pakistan – Tariff Differential Subsidy (TDS)	Notified tariffs politically kept below regulator-determined tariffs; arrears to IPPs mounted.	Annual federal bailout covering TDS (~PKR 1.6 trillion FY2023).	Regularised bailouts become a structural fiscal cost if not reformed.
Argentina – 2002–2015 freeze	Peso devaluation plus a tariff freeze collapsed revenue base.	Government took over utility debts, issued sovereign guarantees, and funded O&M directly.	Prolonged freezes turn utilities into quasi-fiscal arms of the state.
Egypt – Delayed subsidy phase-out (2016–2021)	Tariff reform paused amid social push back.	State treasury continued covering fuel and electricity gaps; later restructured debts.	Delays raise long-term fiscal burden and slow sector reform.
India – State Electricity Boards (1990s–2000s)	Agricultural and domestic tariffs politically suppressed.	Recurrent bailouts under Electricity Acts (2001, 2012, 2020) and a bond program (₹3.5 trillion).	Periodic bailouts became routine, eroding credit discipline.
Philippines – (1990s)	Political tariff controls before restructuring left NPC insolvent.	Government absorbed NPC's debts (~₱200 billion) during 2001 power market reform.	Bailout facilitated liberalisation but showed cost of political control.

Key takeaways for social or politically set tariffs are:

- Tariff setting to achieve social or political goals works when:
  - Efficiency-based regulation is applied to utilities, and tariffs are subsidised by "external" mechanisms.
  - Subsidy funding is transparent and fully budgeted for by the state
  - Regulatory independence to implement cost recovery and performance/efficiency regulation is preserved
- Tariff setting to achieve social or political goals fails when:
  - Tariff (i.e. revenue) caps are imposed on utilities at below-cost recovery levels without compensation
  - Hidden cross-subsidies distort costs
  - Regulators lose authority
- Regulation must balance affordability and utility sustainability
- Protect regulatory independence - even politically/socially-determined tariffs require consistent and predictable rule-based decision-making.
- When tariffs are set below cost, either consumers pay later through tariff hikes, or taxpayers pay through bailouts.
- Sustainable reform requires decoupling affordability from cost recovery through transparent subsidies, prudent costs recovery and regulatory discipline, and fiscal responsibility.

2.2.6 Market-Based Pricing

In this model energy prices are set in competitive wholesale and/or retail markets rather than by a Regulator, but network (infrastructure) tariffs still regulated. Key features are:

- Still requires regulated network tariffs for transmission and distribution.
- Wholesale spot prices fluctuate based on supply-demand balance.
- Retail competition allows consumers to choose suppliers.

The Pros and Cons of market-based pricing are:

Table 15: Pros and cons of market-based pricing

Pros	Cons
■ Encourages renewable investment and innovation through competitive pressures. ■ Gives consumers choice and potential price savings. ■ Reflects real-time pricing for energy	■ Requires strong institutions and transparent market rules. ■ Can lead to affordability concerns if social safety nets are weak. ■ Exposes retailers that must sell through regulated tariffs to under-recovery and financial distress.

Some global examples of multi-year regulation that have resulted in the above pros or cons (and the policy implications of each) are set out in the table below:

Table 16: Global examples of market-based pricing and policy implications

Examples	Observed outcome	Policy implication
IMPROVES ECONOMIC EFFICIENCY AND RESOURCE ALLOCATION		
European Union – Integrated Power Market (EPEX, Nord Pool)	Competitive wholesale markets ensure generators bid based on marginal cost; dispatch reflects least-cost operation across countries.	Market-based pricing encourages efficient dispatch, cross-border trade, and renewable integration.
United States – PJM & ERCOT markets	Locational marginal pricing aligns prices with network constraints and generation cost, leading to efficient investment signals.	Transparent price formation promotes efficient siting and use of infrastructure.
Chile – Spot market under marginal cost pricing	Energy priced hourly based on short-run marginal cost of system; investment attracted to efficient technologies.	Marginal cost pricing can deliver efficiency and investor confidence when supported by long-term contracts.
ENCOURAGES PRIVATE INVESTMENT AND COMPETITION		
UK – Electricity Pool and New Electricity Trading Arrangements (NETA, BETTA)	Liberalisation led to private investment and competitive pricing, lowering wholesale prices in early 2000s.	Open markets attract investment when market rules are transparent and credible.
Australia – National Electricity Market (NEM)	Competitive bidding created clear investment signals for renewables and flexible peaking capacity.	Market-based prices stimulate innovation and technology diversification.
India – Power Exchanges (IEX, PXIL)	Market-based short-term trading improved liquidity and transparency, providing a benchmark for bilateral contracts.	Partial market pricing can improve efficiency even in hybrid regulated systems.
REFLECTS REAL-TIME SUPPLY-DEMAND DYNAMICS		
Texas (ERCOT, USA)	Scarcity pricing allowed prices to rise sharply during peak demand, incentivising demand response and investment.	Real-time price signals strengthen reliability incentives and market responsiveness.
Nordic Region – Nord Pool	Hourly pricing reflects water inflows, temperature, and demand; consumers benefit from flexible participation.	Dynamic pricing reduces system costs when demand-side flexibility is enabled.

Examples	Observed outcome	Policy implication
Chile – Hydro-thermal coordination market	Seasonal price variation promotes efficient water use and dispatch planning.	Real-time and seasonal pricing improve resource efficiency in hydro-dependent systems.
SUPPORTS RENEWABLE INTEGRATION AND INNOVATION		
Germany – Energy-only market with renewables auctions	Market signals plus renewable support schemes attracted large-scale renewable deployment while phasing out feed-in tariffs.	Market-based pricing complements policy support to achieve decarbonisation efficiently.
Spain – Wholesale pool with renewable energy sources participation	Spot pricing integrated renewables competitively into the dispatch stack.	Market signals can coexist with targeted capacity or flexibility mechanisms.
USA – PJM capacity and ancillary service markets	Market-based prices incentivised flexible generation and storage technologies.	Ancillary service pricing complements energy-only markets for reliability.
PRICE VOLATILITY AND AFFORDABILITY RISKS		
Texas (ERCOT) – 2021 Winter Crisis	Energy-only market exposed consumers to extreme price spikes during the winter storm; some retailers and consumers went bankrupt.	Market-based systems need safeguards such as price caps, hedging mechanisms, and retail consumer protection.
Argentina – post-deregulation (1990s)	Market prices fluctuated sharply with fuel import costs and currency crises, leading to affordability problems and eventual re-regulation.	Macroeconomic volatility undermines pure market pricing unless stabilisation mechanisms are in place.
South Australia – High spot price volatility	High renewable penetration and limited interconnection caused extreme hourly price swings before system upgrades.	Complement market pricing with capacity reserves, demand response, and interconnection to manage volatility.
INVESTMENT RISK AND REVENUE UNCERTAINTY		
Germany – Energy-only market before capacity mechanisms	Low wholesale prices from renewables depressed generator revenues ("missing money problem").	Capacity or reliability mechanisms are needed alongside energy-only markets to ensure long-term investment.
UK – Early competitive pool (1990s)	Market power by incumbent generators distorted prices and deterred new entrants.	Effective competition policy and monitoring are essential to preserve investor confidence.
Chile – Drought years (hydro scarcity)	Marginal cost pricing caused sharp temporary price surges and public backlash.	Use financial hedging, diversification, and contracts-for-difference to smooth hydro variability.
MARKET MANIPULATION AND CONCENTRATION RISKS		
California – 2000–2001 Energy Crisis	Strategic generation withholding (e.g. Enron) created artificial shortages and extreme price spikes.	Robust market surveillance and transparency are vital to prevent manipulation.
Spain – Market concentration among large utilities	Dominant players reduced price responsiveness to falling costs.	Market-based pricing requires sufficient competition and oversight.
New Zealand – Early liberalisation (1990s)	Few dominant generators led to sustained high prices and limited competition.	Structural unbundling and active competition enforcement must accompany market reforms.
MAY NEGLECT SOCIAL AND UNIVERSAL ACCESS GOALS		
Sub-Saharan Africa – Partial market reforms	Competitive wholesale pricing did not expand access or protect low-income consumers; governments reinstated social tariffs.	Market mechanisms must be complemented by social protection policies.
India – Merchant plant model (2005–2015)	High merchant exposure left projects financially stranded when demand and tariffs fell.	Balance market exposure with long-term power purchase agreements or capacity obligations.
Philippines – Wholesale Electricity Spot Market (WESM)	Spot prices reflected cost but raised affordability issues for residential users.	Market efficiency should be paired with targeted subsidies or lifeline rates for vulnerable customers.

Key takeaways regarding market-based pricing are:

- Using market-based pricing can boost efficiency and attract investment, but it's important to include safeguards like hedging, reserve capacity, and social support measures.
- Effective governance and clear data reporting help prevent market manipulation and reduce price swings.
- Hybrid systems are common and other markets such as those in the EU, Australia, and Chile blend competitive wholesale prices with regulated retail systems and social policies.
- Policy ensures affordability and governments can play a key role in achieving social goals by providing transparent subsidies or transfers outside of the market system.

2.3 Summary of global revenue requirement regulatory approaches

Mature markets such as the EU, Australia, parts of North America rely on a combination of incentive regulation and competitive wholesale/retail pricing. In contrast, developing/emerging markets (Africa, South Asia, Latin America) still rely heavily on regulation of revenue or politically influenced pricing, largely in response to pressure to make energy more affordable. In the Middle East tariffs remain largely subsidised for political reasons, though reform trends are emerging. Hybrid systems - like Brazil, South Africa and India - try to balance cost-reflectivity with political/social constraints.

The table below summarises the different approaches used in different regions and countries for revenue determination.

Table 17: Different approaches for revenue determination per region and country

Region / country	Regulatory approach	Regulator type	Notes
NORTH AMERICA			
USA	Rate of return (state dependant) + performance-based elements + competitive wholesale in many regions	FERC (wholesale, transmission) and state Public Utility Commissions (transmission, distribution, retail).	Vertically integrated in some states; competitive wholesale markets (PJM, ERCOT, NYISO, CAISO) In states without retail competition revenue is set through cost-of-service regulation
Canada	Rate of return + performance-based regulation (PBR).	Provincial Regulators	Ontario and Alberta have unbundled tariffs; distribution tariffs are regulated, but retail energy prices may be market-linked. Ontario and Alberta have market elements; Alberta has full competitive wholesale. Other provinces vertically integrated generation, transmission, distribution, and retail.
EUROPE: The EU Electricity Directive requires tariffs to be transparent, cost-reflective, and non-discriminatory. Many countries apply long-run marginal cost (LRMC) for network tariffs to encourage efficient use and investment.			
UK	Competitive wholesale/ retail Transmission and Distribution revenue = rate of return + Incentives + Innovation + outputs (RIIO)	Ofgem	Full wholesale and retail market but with price caps for retail. Transmission and distribution network tariffs are cost-based but also forward-looking. Ofgem's Targeted Charging Review separates cost-reflective charges (marginal cost) from residual charges (revenue recovery)
Germany	Competitive wholesale/ retail Revenue-cap regulation + incentives for networks	Federal Network Agency (Bundesnetzagentur / BNetzA) independent regulator for electricity and other services	Transmission/distribution heavily regulated, wholesale and retail fully liberalised. Allowed revenue is fixed for a regulatory period (usually 5 years), adjusted annually for inflation and cost factors. Social support exists for vulnerable customers.

Region / country	Regulatory approach	Regulator type	Notes
France	Competitive wholesale/ retail Revenue-cap regulation + incentives for networks	Commission de Régulation de l'Énergie (CRE): Independent regulator responsible for tariffs, revenue-setting for networks, and market oversight. Ministry for the Energy Transition: Sets policy direction and approves regulated retail tariffs (in coordination with CRE)	Retail tariffs still partially regulated for households - many small consumers remain on regulated tariffs set by the government/CRE.
Spain	Competitive wholesale/ retail Revenue-cap regulation + incentives for networks	National Commission on Markets and Competition (CNMC) independent regulator responsible for approving network tariffs, ensuring competition, and monitoring wholesale/ retail markets	Default (regulated) retail tariffs
Italy	Competitive wholesale/ retail Revenue-cap regulation + incentives for networks	ARERA (Autorità di Regolazione per Energia Reti e Ambiente): Independent regulator that sets methodologies for transmission, distribution, metering revenues, and retail service margins.	Transition from regulated to market-based tariffs. Regulated service for households and small businesses (to be phased out gradually).
Eastern Europe (Poland, Hungary, Romania)	Mix of rate of return and incentive regulation	National regulators	Transition economies balancing EU liberalisation rules with political price control
LATIN AMERICA			
Chile	Competitive wholesale and retail Performance-based regulation for distribution +	National Energy Commission (CNE – Comisión Nacional de Energía): Designs tariff methodologies, sets technical parameters, and calculates regulated revenues.	Model for liberalised reforms in the region. Transmission and distribution revenues are regulated, cost-based, and guaranteed under efficiency methodologies. CNE estimates the efficient costs that a hypothetical "model distribution company" would incur to supply demand in a concession area. Some regulation of retail.
Brazil	Competitive wholesale and retail Rate of return regulation: Transmission guaranteed revenue, Distribution annual inflation/adjustment mechanisms.	ANEEL (Agência Nacional de Energia Elétrica): Brazil's electricity regulator, responsible for tariff methodologies, concession rules, and regulatory reviews.	Strong dual system: "regulated market" vs "free market" Regulated tariffs for small users, free market for large consumers

Region / country	Regulatory approach	Regulator type	Notes
Argentina	Some form of wholesale market. Rate of return for distribution and transmission but politically set tariffs, actual revenues dependent on subsidies rather than tariffs	ENRE (Ente Nacional Regulador de la Electricidad): National electricity regulator, responsible for approving transmission and distribution revenues and tariffs	Chronic under-recovery of costs; utilities financially weak. Distributors rely on direct government subsidies to cover the gap between regulated tariffs and actual cost.
Mexico	Reform to liberalised wholesale market, partly rolled back politically. Rate of return for transmission and distribution	Energy Regulatory Commission (CRE – Comisión Reguladora de Energía): Regulates tariffs for transmission, distribution, and basic retail supply; issues concessions	Market model undermined by recent policy reversals. Regulated tariffs for households and small users. Residential tariffs are often frozen for social reasons, requiring subsidies to maintain revenues.
AFRICA			
South Africa	Rate of return + incentives (NERSA MYPD methodology) for generation, transmission, distribution, and retail, influenced through government policy	National energy regulator of South Africa. Independent regulator for generation, transmission, and distribution.	Eskom dominance, moving to wholesale market. Tariffs subsidies exist between larger customers and smaller customers. No retail competition except for bilateral transactions permitted.
Nigeria	Rate of return framework, but tariffs politically capped. Generation sales through long term PPAs.	NERC (Nigerian Electricity Regulatory Commission): Independent regulator, responsible for tariff methodologies, revenue regulation, and consumer protection	Under-recovery of costs and reliance on subsidies. No retail competition. Implementation gaps and political constraints mean revenues are not fully cost-reflective, and government subsidies remain crucial.
Kenya	Rate of return plus government subsidies for Transmission and Distribution, Generation sales through long term PPAs.	Energy and Petroleum Regulatory Authority (EPRA): Independent regulator that sets electricity tariffs, approves revenue requirements, and licenses market participants.	Affordability pressures dominate, liquidity challenges due to system losses (and poor collection efficiency.
North Africa (Egypt, Morocco, Tunisia)	Political pricing with subsidies, gradual reform to cost-reflectivity	Ministries and regulators	Morocco more advanced on reform
MIDDLE EAST			
Saudi Arabia, UAE, Qatar, Kuwait, Oman, Bahrain	Politically set tariffs, subsidised	Ministries / State Utilities	Extremely low consumer tariffs due to subsidies

Region / country	Regulatory approach	Regulator type	Notes
Jordan	Rate of return for Transmission and Distribution, Generation sales through long term PPAs.	EMRC (Energy and Minerals Regulatory Commission): Independent regulator responsible for tariff methodologies, licensing, and approving revenues for utilities	Targeted subsidies still exist for low-income households, while high-income and industrial customers pay closer to cost-reflective tariff
ASIA			
China	Shifting from "cost-plus" tariff regulation to a revenue cap / permitted income model. Moving towards a wholesale market.	The National Development and Reform Commission (NDRC) and provincial bodies setting electricity tariffs (generation, transmission, distribution)	Gradual move to market-based pricing. Historically administratively set, but reforms are introducing more CoS-based network tariffs, while generation prices are market-linked. Allowing licensed electricity retailers to emerge, especially for large industrial and commercial consumers
India	Rate of return regulation with strong political influence (subsidies for agriculture/poor households)	SERCs (State Electricity Regulatory Commissions)	Chronic gap between cost and revenue Tariffs often deviate from CoS because of strong cross-subsidies (industrial/commercial customers subsidise residential/agriculture)
Japan	Rate of return historically (revenue caps); liberalisation of retail and wholesale	The Ministry of Economy, Trade, and Industry (METI, Agency for Natural Resources and Energy Primary policy and regulatory authority; oversees tariff approvals and revenue frameworks.	Wholesale market with unbundled and regulated Transmission and Distribution. Retail liberalised since 2016.
South Korea	Cost-of-Service, politically influenced	Ministry of Trade, Industry and Energy (MOTIE) sets electricity policy, approves tariffs, and oversees planning.	Retail electricity tariffs are not market-based; they are regulated. Retail tariffs are meant to reflect the cost of supply but often lag due to political decisions. When tariffs are below cost-recovery levels the state utility receives direct fiscal support from the state.
Philippines	Competitive wholesale spot market + regulated distribution tariffs. Allowed revenue = Operating costs + Return on rate base + Depreciation + Taxes, minus non-tariff income.	Energy Regulatory Commission (ERC), regulates tariffs for transmission, distribution, and retail supply margins and approves revenue applications.	One of the most liberalised Asian models. Distribution utilities submit CoS studies to the regulator to set tariffs. Pass-through levies also apply for subsidies and stranded costs
Indonesia	Politically influenced tariffs, large subsidies	Energy Regulatory Commission is not independent, the Ministry of Finance, and the Enterprise Ministry jointly influence tariff and revenue decisions.	Gradual reforms attempted Electricity tariffs are heavily subsidised: consumer tariffs often sit below cost, especially for households. The government transfers funding to cover the difference between cost and tariffs
Thailand	Politically constrained tariffs	Energy Regulatory Commission (ERC)	Strong state role with single buyer model

Region / country	Regulatory approach	Regulator type	Notes
OCEANIA			
Australia	Rate of return + incentive adjustment for network businesses + wholesale market	Australian Energy Market Commission (AEMC) – makes and amends the National Electricity Rules (NER). Australian Energy Regulator (AER) – regulates transmission and distribution networks, sets revenue determinations, monitors wholesale/ retail markets.	Electricity is regulated under a national framework, but with a competitive wholesale and retail market. Distribution and transmission businesses are fully regulated monopolies with multi-year revenue caps under the building block approach. Customers can choose retailers in most states (except some regional networks) and default market offers / regulated retail tariffs still exist as safety nets.
New Zealand	Rate of return + incentive-based regulation + competitive wholesale/retail	Electricity Authority (EA) makes and amends the National Electricity Rules. Commerce Commission (ComCom): Regulates lines businesses (transmission and distribution)	Similar to Australia with a fully competitive wholesale and retail market (no single-buyer model).

According to "**Electricity Regulation in the US: A Guide "** (Jim Lazar) the following key issue should be noted, irrespective of the regulatory method chosen to determine revenue:

> ***"However, it is critical to understand that all regulation is incentive regulation. By this we mean that every regulation imposed by government creates limitations on what the utility can do; but every regulation also gives the utility incentives to act in ways (driven generally by the desire to maximize net income, or earnings) that may or may not promote the public interest. Given any set of regulations, utilities will take those actions which most benefit their principal constituencies — shareholders and management — while meeting the requirements of the regulations."***

3

The Cost of Supply (CoS) study

Once revenue is determined, it is functionalised, classified, and allocated in a CoS study before tariffs are set. The CoS study allocates each cost component appropriately to different customer classes based on their usage and demand, aiming to distribute utility costs according to cost contribution (cause of costs). The "cost causer" refers to the customer whose service use generates the cost. Benchmarking can be used to support cost allocation exercises, but it cannot replace the detailed calculations. Benchmarking works best as a validation or calibration tool, not as the primary means of allocating costs.

In the cost allocation process, according to "The Rate Making process" (Melissa Whited P. C., 2017) there are two primary frameworks used:

- embedded cost of supply/service studies, and
- marginal cost of supply/service studies.

Embedded cost studies examine a single year, allocating the embedded cost revenue requirement based on customer usage patterns during that period. Conversely, marginal cost of supply service studies focuses on how costs change over time in response to variations in customer usage (forward looking). A decision is made in advance when doing the cost of supply study on which approach will be used.

3.1 Approaches to determining cost of supply

3.1.1 Embedded cost

This approach uses costs based on the historic or regulatory costs of building and operating the system. The objective is to allocate costs across all customers classes using rules such as energy use and load profile, capacity, number of customers, position on the network etc. The method is widely used in regulated markets and is applied in South Africa for Eskom and municipalities.

A simple example of how an embedded cost of supply will work is as follows:

- Capacity costs allocated by each class's coincident-peak (CP) share or non-coincident peak.
- Energy costs allocated by load profile.
- Retail costs by customer count and weighting depending on the service level.

3.1.2 Marginal cost

This approach is more complex and allocates costs based on the incremental cost of serving additional load, either in the short run (fuel, variable operating, and maintenance) or long run (capacity expansion). The objective is to send efficient price signals that reflect the true resource cost of consumption and demand. This method may require a residual uplift or credit to get back to revenue requirement.

A residual uplift is an adjustment (usually a surcharge) added on top of marginal-cost-based charges to ensure that the utility's total revenue requirement is fully recovered. The opposite would apply for a residual credit.

The following is an example of how a marginal cost of supply study would work:

- Assume short-run marginal costs (SRMC) per MWh
- Assume long-run marginal cost (LRMC) for capacity per MW
- Calculate each class's SRMC energy + LRMC capacity costs
- Subtotal = Marginal Costs
- Determine a revenue shortfall (or over-recovery) against the revenue requirement
- Add a residual uplift (allocated pro-rata to MWh) to get to the revenue
- Total Revenue = Marginal + Residual

A hybrid approach (combining embedded and marginal) may be used: regulators may blend forward-looking marginal cost principles with embedded cost recovery, such as using marginal costs to determine energy cost changes and embedded to determine network costs.

The following table compares the marginal and embedded costs approaches:

Table 18: Comparison of embedded and marginal cost allocation

Aspect	Embedded cost	Marginal cost
Basis	Historical, average costs	Incremental costs (short-run or long-run)
Objective	Cost recovery	Efficiency and price signals
Revenue recovery	Guaranteed (covers full revenue requirement)	May not recover total costs without adjustments
Economic signal	Weak, may cause cross-subsidies	Strong, encourages efficient consumption/ investment
Complexity	Simple, transparent	Complex, requires advanced models
Stability	Stable tariffs	Can be volatile
Fairness (perception)	Seen as fair (everyone pays share of actual costs)	Can appear unfair if some customer categories pay more than others. May also be difficult for customers and Regulators to understand reasoning
Use Cases	Regulated monopolies, developing markets	Competitive markets, advanced tariff design (TOU, dynamic pricing)

3.2 Cost functionalisation

In this step, costs are separated according to function (generation, transmission, distribution, retail), and whether they are fixed or variable. The purpose of functionalisation is to provide a transparent and methodical link between a utility's actual activities and the tariffs charged to different consumer groups. Without this step, ultimate tariffs may fail to reflect cost causation, leading to inefficiencies, inequities, and societal debate. The objectives in the cost functionalisation step are:

- **Transparency**: Demonstrates how costs are associated with specific utility functions.
- **Fairness**: Ensures that customers pay for the parts of the system they use.
- **Efficiency**: Allows tariffs to reflect the economic signals of capacity, energy use, and customer services.
- **Regulatory compliance**: Provides a standard framework for regulators to audit and approve utility tariffs.
- **Structured approach**: Provides a structured foundation for classification and allocation.

Where there are unbundled markets, generation costs may be excluded from the cost functionalisation step, but at the retail level is seen as a purchase cost. Typical functional categories are:

GENERATION (PRODUCTION)

- Costs of power plants, fuel, purchased power, and generation O&M.
- Further separated into capacity costs (fixed investment and fixed O&M) and energy costs (variable O&M, fuel).

TRANSMISSION

- Costs of extra high-voltage bulk power system, substations, and ancillary services.
- Often split between network services (shared grid) and connection services (dedicated facilities).

DISTRIBUTION

- Costs of high, medium- and low-voltage feeders, transformers, meters, and distribution substations.
- Can be further disaggregated into wires-related costs (capacity-driven) and customer-related costs (service drops, meters).
- Can be split between network services (shared grid) and connection services (dedicated facilities).

CUSTOMER SERVICE / RETAIL

- Billing, metering, call centres, and customer relationship management.
- In unbundled systems, these functions often rest with retailers rather than network utilities.

Figure 2: Typical functional categories

The above process relies on addressing the following challenges:

- Data requirements: Requires detailed asset registers, cost accounts, and load studies.
- Judgment calls: For example, how much of distribution plant is customer-driven vs demand-driven.
- Unbundled vs integrated systems: Different functional boundaries make cross-country comparisons difficult.
- Evolving markets: In competitive or transitioning markets, functionalisation must adapt as retail and wholesale functions separate.

3.3 Cost classification

After functionalisation (splitting costs into generation, transmission, distribution, and customer service), the next stage is classification. According to the document Electricity Regulation in the US: A Guide (Jim Lazar), "determining the right customer classes for each utility is important, and no single method is right for all systems."

Typically, customer classes will be based on residential, industrial, commercial categorisation and may even have additional or sub-classes of these categories.

Costs can be allocated by customer numbers per class, weighting of costs according to the service they receive, their load profile, the amount of energy consumed, capacity, peak demand, or other usage factors.

According to the RAP document "Electric Cost Allocation for a New Era" (Lazar J. C., 2020), the approach selected will vary based on the utility and the rationale supporting the chosen methodology. It is important to identify suitable customer classes with differing cost characteristics at the beginning of a CoS study. The number of classes may differ across utilities and can also depend on the specific costing methodology applied.

Cost classification is therefore the process of determining the cost driver (cost causation) of each functionalised cost element, i.e. whether the cost is fixed or variable and varies at a high-level with:

- Demand (capacity related)
- Energy (kWh related)
- Customer (size of connection/number of customers).

This step is essential because it links costs to the factors that cause them, so ultimate tariffs reflect cost causation. This stage does not result in tariffs but cost reflective tariffs rates and structures ideally where possible should follow the cost drivers identified. This stage also pools costs according to the classification.

In vertically integrated monopolies, all functions, generation, transmission, distribution, and customer service are classified into categories and cost drivers. In unbundled markets, classification covers network utilities (transmission and distribution) because:

- Energy (generation) costs are set competitively in wholesale markets (SRMC/LRMC reflected in prices).
- Retail supply costs are often market-based (competitive), not subject to CoS classification.
- Transmission and distribution remain regulated monopolies and therefore a CoS study focuses on these utilities.

3.3.1 The major classification categories

a. Demand (capacity) related costs

Demand related costs are those costs driven by the capacity installed to meet system peak demand or a customer's reserved demand on the network. Capacity costs can therefore be both associated with generation capacity and network capacity based on how the customer uses their supply. These costs are allocated based on MW and kVA to result in a demand-based unit cost and are driven by:

- Fixed costs associated with generation.
- Transmission and distribution infrastructure associated with substations, transformers and networks sized for peak load or reserved capacity.

b. Energy or consumption related costs

These costs vary directly with the amount of electricity produced and consumed and the time when this electricity is used. These costs are classified as on a kWh basis and driven by:

- Variable generation costs
- Energy losses costs in transmission and distribution networks.
- Ancillary service costs

c. Customer related costs

Customer related costs are those incurred by servicing a connected customer, independent of their demand or energy use, are fixed costs and are driven by costs associated with:

- Metering.
- Billing.
- Customer services such as call centres and IT systems for account management.

These costs are classified on the number of customers and the type of customer being served, for example, a Key Customer would be allocated a higher percentage of the cost.

d. Fixed and variable costs

The classification of fixed costs and variable costs is often a subject of discussion as the allocation has direct financial implications for individual customers or groups of customers. This influences how costs are allocated to different customer classes and affects the final rates and tariff structures.

3.3.2 How classification works

Classification follows the process below:

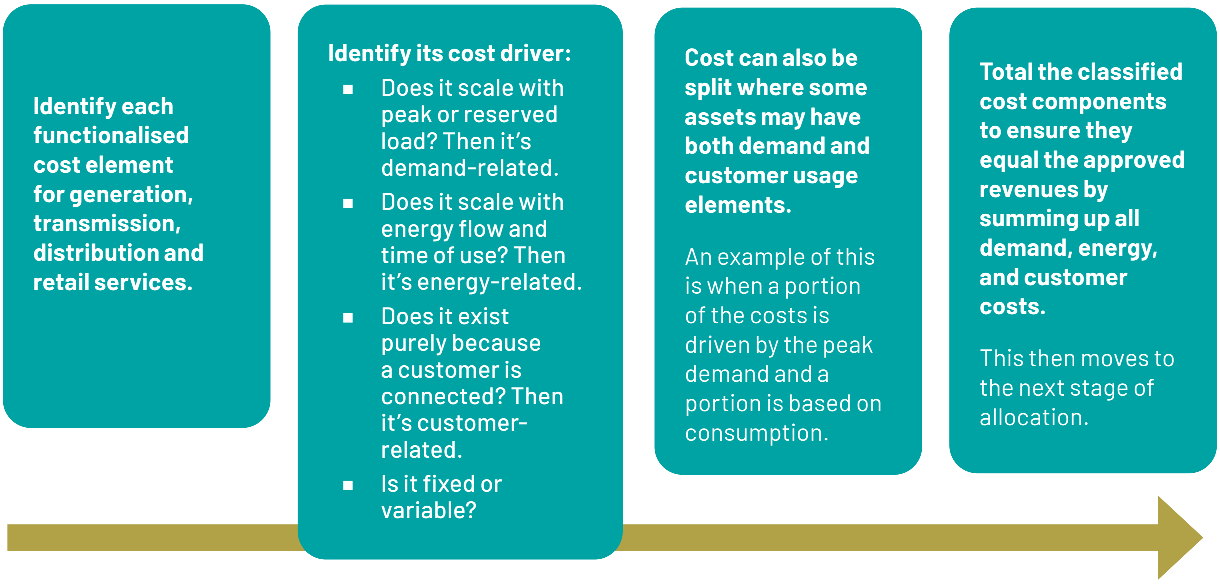

Figure 3: Classification process

3.3.3 Cost classification: bundled versus unbundled markets

The following table shows that cost classification process differs between unbundled and bundled markets. Where there is a wholesale environment, the costs will have already been determined for Transmission and energy and they may be pass-through to retailers or distributors. Distributors will then have to develop their tariffs based on the cost allocated and retailers may then design their tariffs on these pass-through costs.

Table 19: Comparison of cost classification in bundled and unbundled markets

Aspect	Bundled market (regulated integrated utility)	Fully unbundled market (liberalised)
Scope of classification	Applies to all functions: generation, transmission, distribution, retail/ customer service	Applies only to regulated network functions (transmission & distribution)
Generation costs	Classified into demand and energy	Excluded as generation priced competitively in wholesale markets
Transmission costs	Classified into demand, line losses, ancillary services, location, and connection costs	Same principles
Distribution costs	Classified into demand, line losses, voltage, location, and connection costs	Same principles but payable by retailers
Customer service / retail	Classified on number of customers, size of customer and service provided.	Excluded from regulated tariffs as retailers manage customer service

3.4 Cost allocation

The term "allocation" may refer to the total process of assigning revenue requirements to various classes, as well as to this stage in the cost of supply process.

The purpose of the cost allocation stage is to distribute the utility's classified costs fairly and efficiently across customer classes (e.g. residential, commercial, industrial, agricultural) and is the the step between classification and tariff design. In both embedded and marginal cost studies, costs are apportioned based on the number of customers, the peak demand, and the total energy usage. The choice of how to allocate each type of cost typically requires judgments on the part of the utility and different cost components require different allocation methods.

The principles guiding the cost allocation exercise are:

- **Cost causation**: Customers pay according to their impact on costs, such as peak demand affecting capacity expenses.
- **Equity/fairness**: Each group contributes its fair portion of system costs.
- **Efficiency**: Tariffs should promote efficient use and avoid cross-subsidies.
- **Revenue sufficiency**: Allocation must cover the utility's revenue needs.

There are standard approaches applied to CoS study, as set out below:

3.4.1 The major cost allocation categories

a. Demand related costs (capacity) for network and generation capacity

These are costs associated with fixed infrastructure to provide enough capacity to meet system peaks and network peaks. Allocation methods include using the coincident peak, the non-coincident peak, and average and excess method:

b. Coincident peak (CP) method

Typically, utilities allocate demand-related generation and network costs based on class contribution to system peak loads, referred to as coincident peak. This method allocates each class's demand during the system peak hour (or using a few peak hours in a year whereas others consider the highest peak demand in each of several months of the year or the highest 200 or more hours of the year. (Electricity Regulation in the US: A guide, 2nd edition (Lazar J. , 2016)).

In other words, the time the user's maximum demand coincides with the peak hour (s) is the coincident peak used to allocate demand related costs. This peak may be based on historic information or a prediction of the system peak.

This may be an efficient and popular method, but it can also be volatile and politically sensitive. Its advantages and limitations include:

Advantages

- There is a definite cost causation principle as customers who drive the system peak pay more.
- Encourages load management when used in the tariffs as it signals customers to reduce load during system peaks.
- Reflects the reality that system design is based on coincident demand (the combined maximum demand occurring at the same time) and not individual class peaks.

Limitations

- Allocation depends heavily on which hour is defined as the "system peak." One unusual day can skew results.
- A change in customer classification and peaks can make the allocation change each time a cost of supply study is done, resulting in variations in tariffs each time.
- Large industrial users with higher load factors with less peaky load profiles may be allocated lower costs, even though they rely on the system during the peaks.
- Using the coincident peak requires actual hourly metered data hourly and the required smart metering and systems or having to be based on load research data by class of customer where such meters are not available.

c. Non-coincident peak (NCP) method

The non-coincident peak method allocates costs based on each class's own maximum demand, regardless of whether this occurs at the same time as the system or network peak in order words, how much capacity does this class need at its highest point of use, even if that's not at the system peak. This method is commonly used together with CP method for distribution networks.

The advantages and limitations of this method are:

Advantages of using the NCP

- Captures local capacity needs by allocating Distribution assets (feeders, transformers) often sized to meet each class's own maximum load, not just the system peak.
- Stable and predictable as the NCP method tend to vary less year-to-year than coincident peaks.
- Reflects stress each class places on its local part of the network.

Limitations of using the NCP

- Overstates aggregate demand as the total NCP will be greater that the system peak (since peaks do not occur at the same time). Costs are divided over a much larger value, resulting in a lower cost allocation per kVA or MW.
- It provides weak efficiency signals as it will not encourage customers to manage load during system peak periods.
- Large users with flat or non-peaky loads may still pay excessive costs, even if they do not drive system-wide peaks.

d. Average and Excess method

The Average and Excess Method (also called the Average and Peak Method), is another way to allocate demand-related costs in a CoS study. This method is somewhere between the coincident peak and non-coincident peak methods and uses a weighted average of the average demand allocators (weight = system load factor) and the excess-demand allocators (weight = one minus the system load factor). This method splits demand-related costs into two parts:

- An average demand portion where costs are allocated based on each class's average load (recognising that all customers use the system continuously).
- An excess demand portion where costs are allocated based on each class's demand above average load (recognising who pushes the system above its base level, driving new capacity).
- A class's excess demand is the difference between that class's NCP and that class's average demand.

Therefore, every customer pays for their share of the "base system," and heavy peak users also pay for the extra peak capacity they require.

Comparing CP, NCP, and average and excess methods

The following figure compares CP, NCP, and the average and excess demand methods.

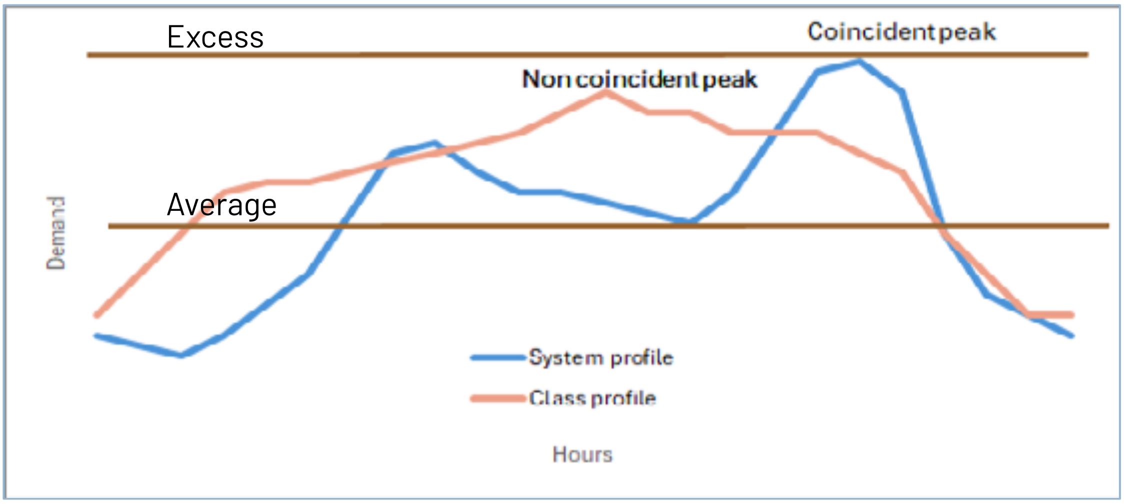

Figure 4: Demonstrating the CP, NCP and average and excess allocation methods for demand

Figure 4 illustrates how capacity cost allocation can differ depending on whether a utility charges customers for:

- their demand at the same time as the system's peak (CP),
- their own highest usage period (NCP),
- their average usage, or Excess
- their extra demand above the average (Excess).

Each approach reflects a different philosophy about who "causes" capacity costs.

3.3.5 Allocation of network costs

It is important that regulated monopoly network costs are ringfenced properly from competitive or optional offerings that a distributor may provide that are not regulated such electric vehicle charging infrastructure.

Network costs may be allocated using any one or a combination of the above methods and further be based different allocation using network configuration based on voltage, shared assets used (substations and transformers) and dedicated assets like metering. Metering may be considered a retail asset and not a network asset.

At each point in the network the demand is allocated based on the customer's positions in the network. Customers can also be allocated to individual customers as a direct service or grouped into pooled costs based on similar types of usage and voltage such as residential customer.

In allocating network costs, customers at higher voltages do not share the assets associated with the assets serving customers at lower voltages, but customers at lower voltages do share all the upstream assets, even though this would typically be based at each voltage level on a coincident peak.

An electricity cost allocation diagram visually represents how total network costs are allocated to different customer categories, using criteria such as usage (for technical losses or demand.

This can be demonstrated in a simplified diagram as follows:

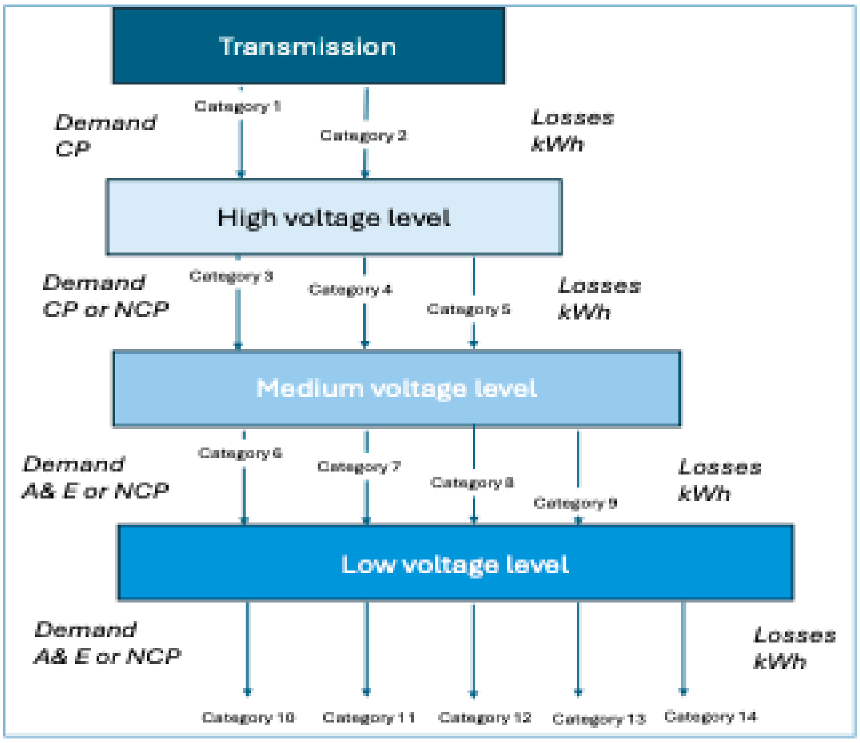

Figure 5: Network Cost Allocation Diagram

Most network costs could be considered fixed and not vary based on consumption, but it is possible to allocate some of the costs as variable either as demand-based costs that vary each month on a customer's actual demand, or based on consumption, or even as a time-of-use signal (see also Section 7.1 on fixed and variable costs and charges)). The allocation of these costs as a fixed demand cost would consider the capacity reserved for this customer.

According to **Electricity Regulation in the US: a guide** (2nd edition (Lazar J. , 2016), the allocation of fixed and variable distribution costs can be a contentious issue as this impacts the ultimate rate design.

> *"The classification of distribution system costs between the customer, demand, and energy categories is a very controversial element of this process—and judgment is involved in the ultimate classification decisions.*
>
> *Many of these costs do not directly vary with any of these factors—they are related to the system density of the service territory, the need to maintain clearances over roadways, and other factors. If costs are classified as customer-related, they are then often used to justify high monthly fixed charges in the rate design, under the presumption that all customers should contribute equally to these costs, rather than in proportion to usage. If costs are classified as demand-related or energy-related, they are apportioned between classes based on usage, and generally result in higher demand and energy charges in the rate design phase of the process."*

There are challenges to be faced when doing a network cost allocation exercise and these are:

- **Availability of data**: a proposed cost allocation study required detailed load profile information (requiring smart meters) which may not always be possible, requiring generic or research-based allocation.
- **Volatility and fairness**: as peak profiles may change each year, the allocation will also change leading to instability in ultimate tariff and so regulators may provide for CoS studies to rather be done on a multi-year basis rather than each year to smooth out the effects.
- **Cross-subsidies and equity**: a CoS study has the outcome of transparently revealing the level of cross-subsidies between different customer categories which may require difficult and unpopular decisions to be made when designing the tariffs.
- **Distributed energy resources and import and export**: customers installing solar PV and batteries have changed the way a distribution grid is used and the methodology on how to allocate costs fairly in this changing environment is complex and not clear-cut.
- **Regulatory transition**: regulators may struggle to adopt new methodologies in this changing environment.
- **Coordination with wholesale / transmission**: distribution cost allocation needs to be consistent with upstream cost allocation to avoid distortions.

3.3.6 Allocation of technical losses

Technical losses are the cost of energy lost as electricity is transmitted through the transmission and distribution grid, separate from non-technical losses such as theft or metering errors. A CoS study should allocate these losses to the different customer categories since they represent the cost of losses to be recovered via tariffs.

Classified as a distribution network cost, technical losses are assigned based on kWh differences between the cost of electricity purchased at the transmission level and sold at each voltage level. Regulators may cap technical losses, guided by technical studies, to encourage better management.

An example:
Energy purchased = 100 MWh
Energy sold = 90 MWh at a particular voltage level
Technical losses = 10%
The cost of purchases is R1.2/kWh
Cost of losses = 10 MWh x R1.2/kWh

Customers supplied at lower voltages experience higher line losses compared to those supplied at higher voltages because their electricity travels greater distances through more network assets from the generation sources.

3.3.7 Energy or consumption related costs allocation

Energy generation cost allocation methods in a regulated integrated utility recognise that customer classes with different load factors and load profiles contribute differently to generation costs over a period. Residential and small commercial customers use more of their electricity during peak times, drawing proportionally more energy from expensive generation plants. For an environment where there is a wholesale market, the retailer is responsible for raising energy related costs to their customers.

Energy cost allocation starts firstly with costs that vary depending on how the electricity is consumed, and at the generation level this would be associated with costs that are variable. For a regulated integrated utility this would depend on how their wholesale tariff is structured between a fixed charge and variable charges.

Costs are typically allocated by time of use (peak/standard, off peak) so that customers that consume more in more expensive peak hours are allocated more of the share of costs. Time of use charges ideally, should reflect the marginal cost of generation but may also include signals that incentivise customer behavior over certain times of the day to assist system operators in managing the power system.

The cost of losses may be added to the energy-based allocated costs depending on voltage and location or shown as a separate loss factor.

Where customers buy from retailers in a wholesale market, it is the retailer that sets the energy price, based on their assumed forecast of the wholesale price.

3.3.8 Customer specific or retail cost allocation

Allocating costs for retail services like metering, billing, administration, and customer support is simpler than other allocation decisions. These decisions are not based on load or network usage, unlike generation and network costs and, therefore, require different principles.

Utilities may classify customers by their supply size (usage or demand), or by voltage level, or what type of revenue class they may be (e.g. residential, industrial commercial) The larger the customer supply size is, the more costs should be allocated as they require individualised and costlier services from the utility.

There are different cost allocation approaches for retail services, such as:

Number of customers allocation
Costs are allocated by the number of customers in each class with the rationale being that these costs exist because customers are be served, regardless of usage. An example is if residential customers make up 60% of the number of connections, they are allocated 60% of the costs. This approach could unfairly allocate costs not based on cost causation as it is not linked to the service being provided.

Weighted allocation
This approach acknowledges the larger the customer category the more resources and system are employed to serve this customer category. Therefore, costs are weighted based on the service provided, for example, an industrial customer category costs 50 times more than the cost of a residential category and, therefore, gets a weighting of 50 times that of a residential customer.

Hybrid allocation
This approach is similar to the weighted approach, but will split the different services into more granular cost categories, for example, meter reading and billing into one category, debt management into another, customer care into another etc.

Energy or revenue allocation
A less common approach would be to allocate costs based on the percentage of kWh sales or revenue in each cost category. This is a simple approach and may be useful where there is limited data available. but it significantly penalises large users which may not accurately reflect the actual costs.

4

Tariff design and tariff structures

The last step in the overall process is designing tariffs. This stage follows the revenue requirement decision and the cost of supply process (functionalisation, classification, and allocation).

However, tariff design does not always fully follow costs that are fully unbundled into different cost driver as practical, economic, social, and political decision and policies will influence the ultimate tariffs structures and the rates. Before designing tariffs, a pricing strategy should be in place with clear objectives guiding on what needs to be achieved and how these objectives can serve customers best.

Tariff design must satisfy potentially conflicting objectives; should recover revenue, must be cost reflective, send the right economic signals, be equitable and fair, and protect venerable customers.

Professor James Bronbright's book on the **Principles of Public Utility Rates,** (Bonbright, 1961) laid out guiding principles for rate design that remain valid for regulators and tariff designers today. His framework is often quoted in CoS and tariff methodologies**.** Bonbright's guiding principles for rate design are summarised as follows:

1. **Revenue sufficiency / effectiveness**
   - Rates should produce enough revenue to cover the utility's revenue requirement (operating costs + capital recovery + fair return).
2. **Fairness in allocation (cost causation principle)**
   - The apportionment of total costs among customer classes should reflect how each class causes those costs.
   - Avoid undue cross-subsidisation between classes.
3. **Fairness in the apportionment of costs between customers**
   - Within each class, rates should be non-discriminatory and equitable. Similar customers should face similar rates.
4. **Discouragement of wasteful use**
   - Rate structures should promote the efficient use of electricity and discourage over-consumption where it drives costs.
5. **Promotion of economically efficient resource use**
   - Price signals should guide customers to use electricity in ways that minimise long-run system costs (e.g., through TOU or demand charges).
6. **Practicality / simplicity / understandability**
   - Rates should be simple enough for customers to understand and for utilities to administer.
7. **Stability and predictability**
   - Rates should provide stable, predictable revenues for the utility and stable bills for consumers.
   - Avoid excessive volatility.
8. **Compatibility with public policy objectives**
   - Rates should align with broader regulatory, social, and environmental goals (e.g., affordability, universal access, renewable adoption).

While the fundamentals of these principles remain valid, these were based on a vertically integrated utility and one where smart metering and distributed energy resources did not exist. According to (Karl R. Rábago, 2018) in revisiting Bonbright's principles of public utility rates in a distributed energy resource (DER) environment, the following is proposed to supplement and modernise Bonbright's principles:

9. **Regulators should fully comprehend and reflect resource value in rates:**
   - In an era of DER and wholesale market competition, regulation is becoming more complex and challenging. While rates may be based on historical costs, they have an impact on future costs and customer behaviour. Regulators therefore need to gear up to manage these challenges with objective, data-driven valuation processes.

10. **Market position consideration**
    - Rate design must account for the relative market positions of utilities, customers, and non-utility providers, and address information asymmetries.
    - Using price signals about cost causation cannot be the only justification or criteria to increase, for example, fixed charges to improve economic efficiency and this may ignore the very real price signals used by utilities.
    - Indeed, the authors can find no principled economic basis or practical market evidence to support the proposition that fixed costs dictate fixed charges. Moreover, the concept of communicating the utility's cost structure as a price signal ignores the very real price signals that these approaches send to the utility, to the relative information position and choice options of diverse customer types, and to markets for DER. The rate should clearly reflect cost components and allow visibility into how bills are calculated.

11. **Economic impact assessment**
    - Rates should be well designed and grounded in practical economic impacts, ensuring customers can respond meaningfully to new rates.
    - Fixed charges can ensure a guaranteed recovery of revenue but do limit the way that customers can save on their bills, no matter how efficiently they use electricity and self-generation.
    - Not all customers would be able to respond to complex tariffs like time of use structures and therefore could be exposed to higher charges in peak periods.
    - New-rate design done in the absence of the customer's ability to respond to these tariffs should not supported and if so and this should be accompanied with education, resources and options to be able to respond.

12. **Capital investment**
    - Rate design should support non-utility parties investing in capital, as this reduces the overall cost for the utility and for society.
    - Regulators will have an increasing burden to account for how rates impact capital investment for all the parties in the electricity industry.

13. **Incentive awareness**
    - Rate design should consider the incentives they create for utilities and customers, avoiding disincentives for efficiency and DER adoption such as high fixed charges.

14. **Accurate accounting of costs**
    - Rates are the process of converting costs in charges. However, this relies on potentially outdated and inaccurate methods of classifying and allocating costs.

15. **Rate design and cost allocation are separate functions, driven by distinct policy objectives**
    - Labelling costs using accounting conventions should not dictate tariff design

While not all the above may be relevant or not necessarily agreed with, they are useful to consider in guiding the development of a pricing strategy and the objectives that would satisfy the needs of the utility and the customer's they serve. Tariff design must now accommodate the changing electricity landscape by correctly focusing on more sophisticated allocation of costs and rewarding customers according to how they can contribute to reducing costs in the system.

The following sets out the process to be followed when designing tariffs.

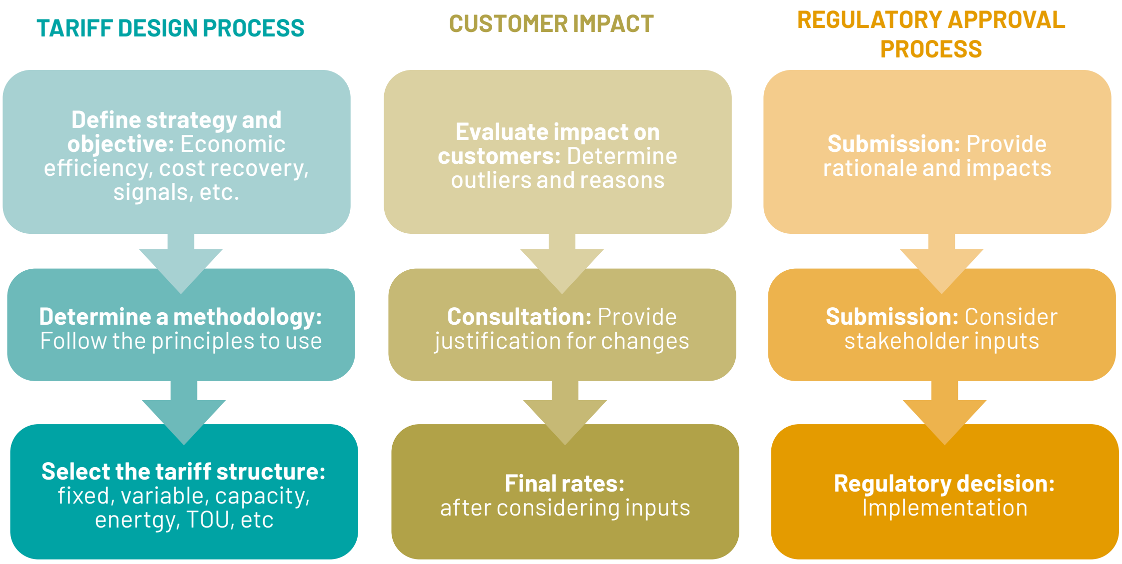

Figure 6: Tariff design process

Coming out of the CoS study would be cost reflective values (not tariffs) based on the different cost drivers used. Regardless how the costs have been allocated into the cost drivers, the next decision would be to decide whether a charge should be bundled or unbundled, fixed or variable (volumetric), based on capacity or per customer, through energy charges (TOU based or not), or any other charge types that may be applicable.

4.1 Rate design decisions

Tariff design is not an exact science, where tariffs will perfectly reflect the cost drivers and where decision may be based on political considerations or policy.

One of the biggest challenges facing utilities today is how to price electricity in such a dynamic and changing technological environment, where DERs have changed the way the grid is used, and customers can reduce their consumption but still rely on the grid to be the insurance when the resource does not produce power. Battery storage and electric vehicle charging provides both benefits to the utility and the customer if used in times outsides of peaks or constrained periods.

This inevitably ends up with the utility having to decide whether tariffs should have dynamic pricing signals in their tariffs, how much of the cost is recovered through fixed charges, who should be protected through subsidies and who should pay the subsidies.

Fixed charges are those charges that do not vary with consumption and may be demand or per customer based. Variable charges are those linked to consumption and based on kWh. The raising of a fixed charge will have a commensurate reduction on the variable charge.

A utility may argue that they want as much of their fixed costs to be recovered through fixed charges as this protects their revenue and reduces their revenue risk associated with lower volumes, while customers and regulators do not like fixed charges as this can harm customers by increasing electricity bills. This can be evidenced in a recent decision by NERSA on Eskom Retail Tariff Plan, where fixed charges were reduced by the regulator and public outcry on small increases to fixed charges.

The following are arguments in favour of fixed charges and the challenges:

Arguments in favour of fixed charges

- **Revenue stability**: Fixed charges ensure utilities recover network and customer service costs that do not vary with consumption such as meters, billing, network capacity.
- **Cost-reflectivity**: A large portion of costs are fixed in the short term such as generation capacity, wires, substations and transformers, so recovering them through fixed charges aligns cost causation with recovery.
- **Reduced volumetric risk**: Protects utility revenues against falling sales from energy efficiency, rooftop solar, or economic downturns.
- **Equity among users**: Every customer benefits from being connected to the grid and power system, so a fixed contribution can be seen as fair, and that unwarranted cross-subsidies are not introduced.

Challenges of high fixed charges

- **Affordability concerns**: Higher fixed charges disproportionately burden low-income and low-consumption customers who can least afford it.
- **Weak price signals**: Reduces consumers' incentive to save energy or shift demand, since less of the bill depends on consumption, which is turn may increase electricity costs.
- **Distributed energy resources**: Penalises solar households who consume less but still pay high fixed costs.

In a paper written by Synapse Energy (Melissa Whited T. W., 2016) on why fixed charges are a problem, stated

> *"For most utilities, there is no need for increased fixed charges. Regulators who decide there is a need to address utility revenue sufficiency and volatility concerns should consider alternatives to increased fixed charges, such as minimum bills and time-of-use rates".*

This paper identified the following common myths below, but these may be seen as controversial:

- **"Most utility costs are fixed."** While costs are fixed in the short-term over the longer term, they become variable.
- **"Fixed costs are unavoidable."** While allocation is based on historic costs, tariffs should be more forward looking to ensure utilities and customers make the right investment through appropriate tariff signals.
- **"The fixed charge should recover distribution costs."** A distribution system is sized to meet the peak demand and while energy usage (kWh) is not a perfect proxy for demand not all customer's burden the system equally.
- **"Cost-of-service studies should dictate rate design."** CoS studies are used to allocate costs, and these are useful tools, they should be based on future marginal cost studies and embedded cost studies.
- **"Low-usage customers are not paying their fair share."** This argument is usually untrue as these customers impose lower costs on the system.
- **"Fixed charges are necessary to mitigate cost-shifting caused by distributed generation."** These concerns are dramatically overstated and while it is true that a distributed generation customer provides less revenue to the utility, this customer also could be providing the utility with low-cost power and avoiding other costs.

The following are arguments in favour of variable charges and the challenges:

Arguments in favour of variable charges

- **Encourages conservation:** With higher per-kWh charges, customers are incentivised to reduce usage.
- **Encourages distributed energy resources:** Makes investments in solar and energy efficiency more attractive by rewarding lower consumption.
- **Affordability for low-use households:** Keeps bills lower for smaller consumers, who are often lower-income.
- **Alignment with policy goals:** Supports energy efficiency and decarbonisation strategies.

Challenges:

- **Revenue volatility**: Heavy reliance on kWh sales makes utilities' revenues unstable, especially as efficiency and self-generation grow.
- **Cross-subsidies**: High-usage customers may bear disproportionate costs, while low-usage customers do not pay their "fair share" of fixed grid costs. This does depend on the cost allocation methodology.
- **Stranded costs risk**: If consumption falls significantly, utilities may under-recover their fixed costs unless tariffs are adjusted to recover these fixed costs.

The global trends on the fixed vs variable charge debate are:

- **Networks are shifting more "residual"/sunk costs into fixed charges**. The UK's Targeted Charging Review moved residual network costs to fixed charges for all users to reduce cross-subsidies and gaming via behind-the-meter load reduction. Suppliers must offer tariffs with lower standing charges (i.e., lower fixed, higher unit rates) so low-use customers are not locked into high fixed costs. (Ofgem, 2019)
- **Income-based fixed charges are emerging (US first).** California's 2024 decision introduced an income-graduated fixed charge and lower per-kWh rates—explicitly to hold networks whole while addressing bill equity. (CPUC, 2024)
- **Australia and New Zealand: push to "cost-reflective network pricing.**" AER-approved Tariff Structure Statements increasingly combine daily fixed charges with TOU/demand components (Ergon Energy, 2025); New Zealand' Distribution Pricing Principles guide a similar shift towards more capacity/fixed charges where justified and clearer signals for peak use.
- **Demand charges for small customers remain controversial.**US regulators and consumer groups frequently oppose residential demand charges as complex and weakly cost-causal at the individual-household level. (Paul Chernick)
- **Developing-country lens: fixed vs variable sits inside a bigger affordability puzzle.** The World Bank's cross-country survey finds widespread use of increasing block tariffs and subsidies; design choices can over- or under-incentivise DER/EVs and complicate cost recovery, so many countries still lean on volumetric recovery plus social tariffs. (Witte)

4.2 Tariff charge types

The most commonly tariff charges are shown in the following table. A tariff structure may comprise a mix of these charge type.

Table 20: Common tariff charge types

Tariff type / approach	Description / mechanism	Key advantages	Key challenges / risks
Flat energy-based charges (flat per kwh)	Consumers pay a fixed energy rate (cents/kWh) regardless of time or demand.	Simple, easy to administer; predictable for many consumers	Poor cost reflectivity (especially for high-peak users); weak signals for shifting load; cross subsidies
Increasing / declining block energy-based tariffs (IBT / DBT)	Volumetric blocks where the rate per unit increases (IBT) or decreases (DBT) with usage bands.	Social / cross-subsidy mechanism; encourages conservation (IBT)	Weak cost alignment; can distort marginal incentives; poorly suited for high-demand or variable load customers. Does not always achieve the objective of protection of the poor or conservation. May also over-incentivise the adoption of rooftop solar.
TOU energy or TOU demand charges	Energy charges or demand charges vary by time block (peak, off-peak, shoulder).	Provides better signals to shift consumption; better alignment with system marginal cost	Requires interval metering; can be complex for customers; may not fully capture demand-driven costs
Demand / capacity charges	Part of the tariff is based on maximum demand (kW) over a billing interval (non-coincident or coincident).	Captures capacity cost causation; encourages users to reduce peaks	Can penalise users with poor load factors; can be volatile; requires measurement
Contracted / reserve capacity charges	Customers choose or contract for a capacity level; billing is tied to that level (with penalties if exceeded).	More predictable for grid planning; encourages customers to select efficient capacity	May underutilise contracted capacity; requires enforcement; choice complexity
Two or three-part charges	Combines fixed charge + volumetric charges + demand or capacity component.	Balances predictability, cost causation, and simplicity trade-offs	Requires careful calibration of components; risk of over/under weighting
Real-time pricing	Prices vary by time and location based on marginal generation, losses, and congestion	Highly cost-reflective; strong economic signalling	Complexity, volatility, requires advanced metering & systems; customer acceptance
Cost causation charges	Tariffs are designed so that customers pay in proportion to how they cause costs (peak, load shape, location).	High theoretical cost reflectivity and equity (if well-measured)	Data-intensive, complex, may conflict with stability / simplicity
Dynamic tariffs (critical peak/ super off-peak charges)	Tariff rates adapt in near real-time to system constraints or surpluses) but built to preserve equity for low-response or vulnerable customers.	Encourages demand flexibility; better adapts to variable supply	Overly complex; relies on customer response, need real time data and system, may shift burden to less flexible users
Charges linked to fixed volumes	Tariff increases when consumption or demand exceeds or is lower than a threshold; penalising excessive or lower volumes (take or pay).	Targets fixed volumes with potentially favourable rates	Can be punitive if volumes are higher or lower than contracted for, unless there is an ability to buy or sell the difference

5

Implications for South Africa

In South Africa there are guiding principles related to cost of supply and tariff setting and these are:

White Paper on the Energy Policy of the Republic of South Africa (DEE, 1998)

This document sets out the high-level policy objectives for the energy sector (affordability, access, efficiency, economic growth) and calls for integrated planning and transparent pricing. It established a policy framework for cost-reflective tariffs and transparent methodologies that later instruments operationalise.

The Electricity Regulation Act of South Africa 2006 as amended (ERA) (2025)

The ERA is the legal basis for CoS-based tariff approval and licence conditions and assigns NERSA the role of regulating electricity prices and tariffs and approving cost recovery plus a fair return on assets for efficient licensees. Tariffs cannot be discriminatory unless justifiable and approved otherwise by NERSA.

The amendment provides for the unbundling of Eskom Transmission as a separate legal entity from Eskom, the establishment in the future of an independent Transmission System Operator and the introduction of a wholesale market. This will have an impact on how tariffs are developed and how costs will be allocated.

The Electricity Pricing Policy (EPP) (DEE, 2008)

NERSA is mandated by the ERA to implement government policy and the EPP is one such instrument. The EPP is clear that cost-reflective pricing is a target to be aspired towards, both in level (revenue determination) and for tariff charges.

The EPP sets out the structure of a wholesale tariff and for retail tariffs, unbundled tariffs components that should or could be used and these charges should be motivated by a cost of supply study undertaken at least every 5 years. The wholesale tariff would be the charge raised at the wholesale level for energy, capacity and Transmission related charges for networks, losses and ancillary services.

The EPP is under review.

NERSA's MYPD methodology (NERSA, Multi year pricing determination methodology, 2016)

The MYPD is NERSA's regulatory mechanism for determining Eskom's allowed revenues over a multi-year horizon (usually 3–5 years). It uses a rate of return methodology, with revenue cap, has some performance incentives and allows for a clearing mechanism for retrospective adjustment due to factors outside of Eskom's control, based on audited financial statements.

This methodology does not deal with tariff charges, but results in an average price increase. Eskom currently applies for their Generation, NTCSA and Eskom Distribution revenue separately, but the application of the process is flawed as it applies the same increase to all the charges even though the revenues increase for each entity is different. The only way to correct the tariffs is to do a new cost of supply study and for NERSA to apply separate increases to each party's revenue.

NERSA's CoS framework (NERSA, Cost of Supply Framework, 2020)

This framework is applicable to municipal distributors and combines both a revenue determination process, cost of supply and tariff charges. It is the regulator's template for acceptable methods and allocators and the documentation standard used for tariffs.

The Distribution Tariff Code v6.2 **(NERSA, Distribution Tariff Code v6.2, 2022)**

The Distribution Tariff Code is a regulatory instrument as a condition of a distribution licence that must be complied with and that establishes objectives, principles, and guidance for how distribution network and retail tariffs, as well as connection charges, should be structured by licensed distributors. It aligns to the EPP and complements other Codes and regulatory instruments.

Eskom's Strategic Pricing Direction (Eskom, Strategic direction and tariff design principles for Eskom's tariff, 2017)

This document lays out Eskom's view of how tariffs should be structured to cost-reflective, unbundled tariffs with appropriate TOU/seasonal differentiation, demand components, and clearer links to cost drivers.

Eskom's 2024 retail tariff plan (Eskom, Eskom Retail Tariff Plan, 2024) was based on an updated cost of supply study (Eskom, 2024) and achieved most of what is contained in the strategy document.

It is expected that once the EPP is revised, this may require updates of some of the above documents.

5.1 Cost of supply studies under the new South African Wholesale Market

It is not yet clear is how (in particular) Eskom Generation will be regulated by NERSA once the market is fully transitioned. Transmission and Distribution will be fully ringfenced and regulated using a NERSA approved methodology, and Distributors may also want to offer unregulated (competitive) services also ringfenced from the regulated activity's services.

It is proposed under the draft Market Code v2.1 (still to be finalised and approved by NERSA at the time of writing) that a wholesale tariff be developed to recover costs at the wholesale level for energy and Transmission network services. This tariff would need to follow a methodology and rates that would be approved by NERSA and will be based on the following structure:

- TOU energy charges to cover Eskom Generation variable costs plus the cost of the government Section 34 of ERAA IPP procurement costs.
- Generation capacity charge (R/MW) to cover Eskom Generation capacity related costs.
- Legacy charges that recover the cost of the hedges in the vesting contracts and the legacy contracts. The vesting contract will be between the Central Purchasing Agency (CPA) within the National Transmission Company of South Africa (NTCSA) and Eskom Generation, and between the CPA and Distributors that are Market Participants (those that qualify). The Legacy Contract will be between the Section 34 IPPs and the CPA. These contracts will contain a hedge against the spot price in the market and the prices contained in the vesting contracts and PPA's. For Distributors that are Market Participants, the hedge will be the difference for set volumes between the spot price and the Wholesale energy charge.
- Transmission charges,
  - Use of system network charges
  - Ancillary service charges
  - Loss charges
- Subsidy charge to be raised at the wholesale level. This would require a framework to be developed by NERSA.

It is further proposed in the Market Code v2.1 that the vesting contracts will be transitioned by removing the hedge over time or not at all, but the period for the transition period is to be determined by NERSA.

The wholesale tariff will become the input cost for Distributors that are Market Participants when doing a cost of supply study to update retail charges and structures. Eskom in their 2024 retail tariff plan (Eskom, Eskom Retail Tariff Plan, 2024) structured their retail charges on the above wholesale tariff structure.

Distributors that are not Market Participants will continue to purchase electricity at Eskom's Distribution retail charges. Once the vesting contracts expire, Distributors in their retail trading function[4] buying from the market

4 Under the ERA, there should be separate Trading and Distribution Licenses. This will mean that all current Distribution Licences will have to evolve into these separate functions.

will be fully exposed to the spot market prices. Some protection from NERSA will be required for events outside of their control. For example, the events that causes the electricity crisis in the UK due to the Ukraine war, resulted in the bankruptcy of Retailers and resulted in OFGEM stepping in.

The current NERSA MYPD methodology will need to be updated, and it is possible that NERSA may revise the current rate of return methodology to new methodologies to separately apply to Eskom Generation, the NTCSA (or parties that supply Transmission services) and Distributors. Stronger incentives should be included to reward or penalise poor performance. Currently if, for example Eskom Distribution performs earns more revenue than allowed, the Regulator will take that away in future years through lower price increases. If Eskom Distribution does worse than that allowed, then the Revenue Clearing Account (RCA) mechanism requires Eskom to motivate for the shortfall, which may or may not be allowed by NERSA.

What is important will be the reliance on much better forecasting to set both revenues and tariffs at the retail and wholesale level, to reduce reliance on the RCA. This will require larger customers (including municipalities) that buy at the retail level, to forecast better and the introduction of penalties for incorrect forecasting. This is an area of concern as forecasting is often a difficult area to predict and manage as there are no consequences for incorrect forecasting.

5.2 Recommendations for South Africa

5.2.1 Revenue

Eskom (including the NTCSA) has a multi-year revenue decision with the RCA mechanism, and municipal Distributors are only given annual decisions with no RCA mechanism.

It is recommended that:

I. the MYPD methodology and the NERSA Cost of Supply framework are revised as set out below, and
II. all Distributors must have the same multi-year revenue determination methodology.

Recommended revisions include:

- Prudency tests for allowable costs should be benchmarked against global best practices, where relevant for local circumstances.
- The revenue determination method should have stronger incentives to manage costs by fixing revenues in advance and letting the utility keep any efficiency gains or penalties for inefficiency until the next reset.
- The RCA mechanism could be included but narrowed to only consider factors outside of the utility's control and potentially capped to impact to reduce volatility of prices.
- Standard templates should be used to provide cost and volume (kWh, demand, customer numbers) information for the Regulator to enable faster turn-around and for the avoidance of calculation errors.
- The regulation of Eskom Generation may evolve over time as the wholesale market evolves.

5.2.2 Cost of Supply studies

NERSA should require cost of supply studies to be conducted regularly, or at least whenever there is a significant change. A national CoS template with predetermined allocation rules should be used for this purpose, such as the following example:

- Coincident peak for shared capacity (primary substations, upstream lines).
- Non-coincident peak where diversity is low (local networks).
- Average and excess to reconcile customer classes with differing load factors.
- Loss factors by voltage and geography and applied transparently to energy charges.
- Embedded generation: separate export and import use of system charges and clear crediting for exports under net-billing.

The CoS study to be audited and allocators, steps, and customer categories and cost drivers and unit rates motivated and published. Consideration of the introduction of a Review Panel to sign off on compliance with the CoS methodology. Audited CoS is the spine of any credible tariff filing and is standard in AER (Australia), NZ Commerce Commission, and EU regulators.

5.2.3 Tariff Design

It is recommended that the following should be mandated by NERSA:

- Tariffs to be based on a CoS study.
- Retails tariffs, except for lifeline tariffs[5] should be unbundled into the following components:
  - The wholesale tariff structure reflected as is (that is, TOU energy, capacity charge, legacy charge, Transmission use of system, losses, and ancillary services)
  - Distribution networks charges to be split into fixed and variable components depending on the customer category being served. Minimum bills could also provide some protection for fixed cost recovery.
  - Transparent loss charges for Distribution losses cost.
  - Customer service and administration charges raised as fixed charges.
  - Transparent subsidy charges.
- Strong efficiency signals encouraged through TOU energy charges and allowance for dynamic pricing especially when exposed to the spot market prices.
- Equity and affordability addressed through a combination of lifeline tariffs for low-income households and targeted subsidies (like free basic electricity) to service providers, which are based on fiscal transfers rather than artificially low tariffs. Per the EPP, NERSA and the DEE is required to develop a subsidy framework. Individual utilities should not be deciding which users get subsidised and which users do not.
- Distribution energy resources supported by implementing the approved NERSA rules for net-billing with time-differentiated export rates, and with no avoidance of fixed charges or contribution to subsidies.
- Ensure proper cost recovery when there is wheeling with standardised charges, no double counting of use of system charge and unbundled loss factors.

This approach aligns with global practices, even though TOU tariffs and comparatively higher fixed charges do not appear to be applied universally.

5 Tariffs that are below cost to meet social needs and do not have a fixed charge.

6

Conclusion

Well-designed, cost-reflective electricity tariffs resulting out of with a strong revenue determination methodology and a justifiable CoS study should result in tariffs that reduce utility costs, influence customer investment choices, maximise energy efficiency and optimise the way the grid and the overall power system is used.

Tariffs should ideally follow the cost structure, but as noted in the sections dealing with fixed and variable cost allocation and charges, it is unlikely that there will be consensus between the utilities and customers, and it will be up to NERSA to decide on the fairest approach.

There are evolving trends and practices for CoS studies and tariff design, such as:

- Revenue determination methodologies need to be updated/revised as circumstances change and should include incentives.
- Allowable costs should be based on strong prudency tests.
- Cost causation and allocation methodologies should be justifiable and transparent as they impact the ultimate tariffs.
- CoS studies are becoming more accurate, especially due to data availability through smart metering.
- Tariffs reflecting cost drivers provide the utility with more information about their costs and recovery of revenue.
- There is a need to move towards higher fixed recovery, but this needs to be considerate of customer impacts and potential unintended consequences.
- More dynamic tariffs that optimise efficiency and fairness; to manage system surpluses and constraints and to mitigate the impact of a wholesale market.
- There is a need for subsidisation to protect vulnerable customers, which should be targeted and not necessarily funded only through tariffs.

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