ENERGY REGULATORS
REGIONAL ASSOCIATION

GRID INVESTMENTS: REGULATORY EVALUATION AND INCENTIVES

ERRA Member Survey and Case Studies

Prepared by
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GRID INVESTMENTS: REGULATORY EVALUATION AND INCENTIVES

Regulatory assessment of grid investment plans and regulatory incentives for grid investments execution – ERRA survey and select case studies

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In cooperation with ERRA Electricity Markets and Economic Regulation Committee

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Executive Summary

This report examines how energy regulators evaluate grid investment plans and implement incentives to ensure efficient and timely introduction of critical electricity infrastructures. Building on previous ERRA EMER Committee work, and on a deep survey of 13 ERRA regulators, it provides a comprehensive analysis of regulatory approaches across multiple jurisdictions, both EU and non-EU, offering insights into current practices and emerging trends. Five in-depth case studies are examined in chapter 5.

The context

Electricity grids across jurisdictions are facing concurrent challenges of integrating growing renewable energy capacity, accommodating increasing electricity demand, and high reliability standards at both transmission and distribution levels. To address these challenges, smart grid technologies present viable solutions for optimizing existing infrastructure while enabling enhanced demand-side management and seamless renewable integration.

However, implementing these technologies requires significant investment, which necessitates regulatory frameworks that carefully balance the need to enable necessary infrastructure development while protecting consumers from unnecessary costs. As part of this balancing act, cost-benefit analysis methodologies are evolving beyond traditional metrics to capture broader economic, environmental, and social benefits.

Complementing these technical and economic considerations, effective stakeholder engagement throughout the planning process has emerged as an essential element for successful grid development projects, ensuring that diverse perspectives are considered, and potential obstacles are identified early.

The Regulatory Framework for Grid Planning Evaluation

Modern grid planning requires addressing both conventional infrastructure needs and emerging technological solutions through regulatory assessment frameworks that are both robust and flexible.

A key approach to achieving this balance is through structured project categorization (reliability/resilience, expansion, competition/market functioning), which allows each type to be assessed against appropriate criteria tailored to its specific objectives. Within these assessment processes, risk methodologies have expanded significantly and now need to consider climate change impacts, cybersecurity threats, and technology evolution alongside traditional technical and financial risks.

This complexity is further amplified for cross-border projects, where regional coordination becomes essential and requires sophisticated frameworks for cost allocation and benefit sharing among participating jurisdictions.

Given these multi-dimensional considerations, regulatory oversight must strike a delicate balance between providing certainty for project developers and maintaining flexibility to adapt as technologies, markets, and environmental conditions continue to evolve.

KEY TAKEAWAYS FROM THE ERRA SURVEY ON GRID PLAN REGULATORY ASSESSMENT

The survey reveals that most jurisdictions have established well-structured, legally-based processes for evaluating grid investments, with requirements predominantly set by regulatory authorities. While basic elements such as infrastructure descriptions, cost estimations, and implementation timelines are consistently required across jurisdictions, there is considerable variation in more advanced requirements. Specifically, elements addressing renewable energy integration and environmental impact assessments show significant differences in implementation depth and breadth.

Similarly, cost-benefit analysis (CBA) approaches are still widely ranging, from comprehensive methodological frameworks to more ad hoc analyses, with differences also in the economic thresholds that trigger CBA assessment. A notable area for improvement across most jurisdictions is multiple scenario planning and uncertainty analysis, as most countries currently focus primarily on short to medium-term planning horizons spanning only 3-10 years, potentially limiting their ability to address long-term transitions.

Although stakeholder consultation is widely recognized as standard practice, its implementation varies considerably, with duration requirements ranging from as little as 30 days to as much as 6 months. Furthermore, limited stakeholder participation is frequently cited as a persistent challenge, suggesting that formal consultation processes may not always achieve their intended engagement objectives.

KEY TAKEAWAYS FROM THE ERRA SURVEY ON INCENTIVES FOR INVESTMENT EXECUTION

Financial viability assessment emerges as a standard requirement implemented by most regulatory authorities, forming the foundation of investment execution frameworks. However, approaches to tariff recognition show considerable variation, ranging from recognition at project approval to recognition only upon final commissioning, reflecting different risk allocation philosophies between network operators and consumers.

Despite the importance of timely and efficient project execution, advanced incentive frameworks specifically designed to promote these outcomes remain limited across surveyed jurisdictions. Notable exceptions include Oman's Project Delivery Incentive scheme (detailed in paragraph 4.2) and France's implementation (explored in paragraph 5.2), which provide valuable models for consideration.

The survey results also reveal a clear pattern whereby countries with more mature regulatory systems have established more comprehensive monitoring processes with regular and structured reporting requirements, enabling closer oversight of investment progress. This observation highlights the evolutionary nature of regulatory frameworks, suggesting that monitoring systems develop progressively alongside other aspects of regulatory maturity.

Across all jurisdictions, regardless of their development stage, achieving an appropriate balance between thorough regulatory oversight and sufficient operator flexibility remains a key challenge in developing effective investment monitoring frameworks, requiring continuous refinement as systems evolve.

Recommendations for Grid Investment Planning and Execution Regulatory Frameworks

Based on the results of the survey and case studies collected, the following recommendations have been formulated.

Grid Optimization	Prioritize efficient use of existing infrastructure through Grid Enhancing Technologies (GETs) and other measures before expanding networks
Standardized Assessment	Implement structured templates for grid plans with clear minimum requirements for both TSOs and DSOs
Cost-Benefit Analysis	Develop proportionate CBA frameworks with appropriate thresholds and standardized methodologies for multiple benefit categories
Scenario Planning	Enhance long-term planning with multiple scenarios to address fundamental uncertainty and cross-sectoral integration
Stakeholder Engagement	Strengthen consultation processes with adequate duration (3-6 months) and multiple engagement methods
Investment Recognition	Design tariff treatment approaches that balance risk allocation while incentivizing timely implementation
Execution Incentives	Implement balanced mechanisms with reasonable deadbands for timelines and clear reference costs for efficiency
Monitoring Systems	Establish comprehensive frameworks with clear amendment thresholds and regular reporting requirements

Conclusions and Next Steps

As power systems worldwide face unprecedented challenges from renewable integration, electrification, and infrastructure modernization, effective regulatory frameworks for grid investment evaluation and execution incentives become increasingly critical. While regulatory approaches must be tailored to local conditions, the convergence towards more structured assessment, broader benefit consideration, and outcome-based incentives represents a promising direction for enabling the necessary grid transformation.

The report provides first key takeaways about the regulatory challenges. Further work is needed to develop a comprehensive regulatory toolbox that can support energy regulators in facilitating the substantial grid investments required for avoiding the risk of gridlock and allowing the energy transition while ensuring consumer protection and economic efficiency.

LIST OF ACRONYMS

EMER	ERRA Electricity Markets and Economic Regulation Committee
EU	European Union
CBA	Cost Benefit Analysis
TSO	Transmission System Operator
DSO	Distribution System Operator
NDP	Network Development Plans
PCIs	Projects of Common Interest (of the European Union)
RES	Renewable Energy Sources

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France	Commission de Regulation de l'Energie (CRE)	**Armenia**	Public Services Regulatory Commission (PSRC)
Hungary	Hungarian Energy and Public Utility Regulatory Authority (MEKH)	**Georgia**	Georgian Energy and Water Supply Regulatory Commission (GNERC)
Latvia	Public Utilities Commission (PUC)	**Moldova**	National Agency for Energy Regulation (ANRE)
Lithuania	National Energy Regulatory Council (NERC)	**North Macedonia**	Energy, Water Services and Municipal Waste Management Regulatory Commission (ERC)
Romania	Romanian Energy Regulatory Authority (ANRE)	**Oman**	Authority for Public Services Regulation (APSR)
		Saudi Arabia	Saudi Electricity Regulatory Authority (SERA)
		Türkiye	Energy Market Regulatory Authority (EMRA)
		USA, Rhode Island	Public Utility Commission Rhode Island (PUC-RI)[1]

[1] PUC-RI is not a direct member of ERRA but it is affiliated indirectly through the U.S. National Association of Regulatory Utility Commissioners (NARUC).

1. INTRODUCTION

1.1 THE ROLE OF ELECTRICITY GRIDS IN ACHIEVING SUSTAINABLE ENERGY GOALS

The electricity grid stands at the intersection of two major global challenges: the transition to sustainable energy and the imperative for economic development. As a consequence, electricity grids play a fundamental role in achieving sustainable energy goals while facilitating development and increased electrification. Grid must not only adapt to the challenge of a growing penetration of variable renewable energy sources, but also expand and sustain growing energy demand related to economic growth.

UNDERSTANDING GRID ARCHITECTURE: TRANSMISSION VS DISTRIBUTION

The electricity grid consists of two primary components: transmission networks and distribution networks, each facing distinct challenges in both energy transition and development. Transmission networks comprise high-voltage power lines that transport electricity over long distances from large generation facilities to local distribution systems. These networks typically operate at voltages above 35 kV (typically, higher than 100 kV) and form the "superhighways" of the electrical system; in most countries, they have a meshed configuration and ensure a very high level of reliability. Distribution networks, operating at medium (1-35 kV) and low (<1 kV) voltages, deliver electricity from substations directly to end consumers through a complex of circuits and transformers.

The energy transition affects these two levels of network differently. Transmission networks must adapt to accommodate large-scale renewable energy projects, such as offshore wind farms and utility-scale solar installations, often located far from consumption centres. This requires significant expansion and reinforcement of existing transmission infrastructure, as well as the development of new corridors to connect renewable resources to load centres. Distribution networks, meanwhile, face the challenge of integrating distributed energy resources (DERs) like rooftop solar, small-scale wind, and electric vehicle charging stations. Furthermore, distribution networks were traditionally designed for one-way power flow but must now handle bidirectional flows and increased voltage fluctuations caused by distributed generation, mostly sourced from variable renewables. This transformation requires substantial upgrades to control systems, protection equipment, and monitoring capabilities.

MODERNISATION OF ELECTRICITY GRIDS

The concept of "smart grids" has emerged as a new model, incorporating advanced digital communications, automated control systems, and intelligent monitoring capabilities. At the transmission level, these technologies enable area-wide monitoring and control, helping operators manage power flows across regions and maintain system stability. At the distribution level, smart grid technologies facilitate real-time load balancing, demand response management, and efficient integration of local renewable resources. Smart grid technologies offer substantial benefits in developing regions, where they can help optimize limited infrastructure and improve reliability. Advanced metering infrastructure (AMI) helps utilities reduce losses, improve billing accuracy, and manage demand more effectively.

Both network levels support demand-side management and energy efficiency improvements. By providing real-time data on energy consumption and grid conditions, these systems help optimize energy use, reduce waste, and lower overall carbon emissions. This capability of smart grid is particularly important for achieving sustainability targets and managing peak load demand.

In developing regions, the primary challenge often lies in basic grid extension and reliability improvement. Some areas face the dual challenge of expanding access while simultaneously modernizing existing infrastructure. This creates a unique opportunity to "leapfrog" traditional grid development by implementing advanced technologies from the start, although this is often challenged by financial constraints.

Transmission networks must expand to connect new industrial zones, urban developments, and previously unserved regions. This expansion requires massive investment in infrastructure, particularly in emerging economies where electricity demand is growing rapidly due to industrialization and rising living standards.

Distribution networks face the challenge of connecting millions of new customers while upgrading existing infrastructure to handle increased load from urbanization and rising per-capita consumption. This includes strengthening networks to support the electrification of transport and heating, which adds significant new demand to local grids.

Modern grids must evolve to address three concurrent challenges: integrating renewable energy, meeting growing demand, and improving reliability. This evolution requires sophisticated planning that considers both immediate needs and future flexibility.

The transformation of electricity grids faces distinct challenges at transmission and distribution levels. Transmission networks require investments in new infrastructure to connect renewable energy zones to load centers, often facing lengthy permitting processes and public acceptance issues. The integration of large-scale renewable energy also introduces stability challenges that require sophisticated control systems and energy storage solutions.

Distribution networks face the technical challenge of maintaining power quality and reliability with high penetration of DERs. Solutions include also “non-wired” approaches, like implementing advanced voltage control schemes, deploying local energy storage, and developing more sophisticated protection systems.

SYSTEM NEEDS AT TRANSMISSION AND DISTRIBUTION LEVEL

Transmission grid investment needs can be categorized at least into four main areas:

- basic infrastructure expansion: extending networks to unserved areas and strengthening existing infrastructure to meet growing demand;
- modernization: upgrading systems to improve reliability, providing stability for increasingly complex power flows and enable smart grid functionalities;
- renewable Integration: adding infrastructure and control systems to accommodate clean energy sources; in developing economies, these investments often need to happen simultaneously rather than sequentially, creating significant financial and technical challenges;
- generation efficiency and competitiveness: connecting regions enables regional power trading and optimize resource use, with positive effects on market prices in case of electricity wholesale market competition. Under this perspective, the development of cross-border interconnections becomes particularly important, allowing regions to share resources and balance variable renewable generation across wider areas.

Distribution systems face perhaps the most complex evolution, needing to:

- connect new customers and support increasing per-capita consumption;
- integrate distributed energy resources, esp. variable renewable generation units;
- support electrification of transport and heating (e.g. e-mobility, heat pumps, etc.);
- maintain power quality with increasingly reverse power flows (from lower to higher voltages)
- enable demand-side management and energy efficiency initiatives.

The electricity grid of the future must serve as both an enabler of sustainable energy and a foundation for the future economy. This dual role requires careful planning, significant investment, and innovative approaches to both technical and financial challenges. Success will require coordination between governments, regulators, utilities, private sector partners, and development institutions to ensure that grid development supports both sustainability goals and economic growth.

The path forward will likely involve a mix of traditional infrastructure expansion and innovative solutions, with different regions adopting approaches suited to their specific circumstances. What remains constant is the need for grids that are robust enough to support development while flexible enough to accommodate an increasingly sustainable energy future. The successful transition to sustainable energy systems depends heavily on the modernization of both transmission and distribution networks. While these networks face different challenges, their evolution from traditional infrastructure to smart, flexible systems is essential for achieving ambitious climate and sustainability goals. Success in this transformation requires continued technological innovation, supportive policy frameworks, and significant investment in infrastructure modernization at all voltage levels.

The electricity grid of the future must be capable of supporting a fully sustainable energy system while maintaining reliability, accessibility, and affordability for all users.

1.2 Grid Planning and Investment Evaluation: The Role of Energy Regulators

Energy regulators play a crucial role in facilitating effective grid development while ensuring that investments serve the public interest and maintain economic efficiency. Their primary function is not to conduct grid planning directly, but rather to establish the framework within which grid operators can plan and implement network developments effectively. Regulators must strike a delicate balance between enabling necessary grid investments and protecting consumers from unnecessary costs.

Energy regulators should establish the foundational requirements and methodologies that guide grid planning processes. These frameworks typically mandate that grid operators follow specific approaches in identifying, evaluating, and prioritizing infrastructure investments. It is internationally recommended that effective regulatory frameworks promote transparency, stakeholder engagement, and alignment with broader energy policy objectives while preserving the technical autonomy of grid operators.

A key regulatory function involves setting clear criteria for evaluating the necessity and efficiency of proposed grid investments. These criteria typically encompass technical, economic, and environmental considerations. Regulators must ensure that grid operators' planning methodologies adequately account for factors such as:

- The integration of renewable energy sources and the transition to a low-carbon economy;
- Security of supply and system reliability requirements;
- Economic efficiency and cost-effectiveness of proposed solutions, possibly comparing among diverse feasible options that respond to the system need;
- Social and environmental impacts of infrastructure development.

The regulatory approach to investment evaluation has evolved significantly in recent years. Traditional cost-of-service regulation is increasingly being supplemented or replaced by incentive-based mechanisms that encourage grid operators to find innovative and cost-effective solutions. As noted in several reports, these mechanisms can include provisions for sharing efficiency gains between grid operators and consumers, thereby creating incentives for optimal investment decisions. Recently, also “benefit-based” incentive regulation has been proposed and implemented in some jurisdictions, sharing a part of net benefits.

Cost-Benefit Analysis Frameworks

Modern regulatory frameworks for cost-benefit analysis (CBA) must capture a comprehensive range of impacts across different stakeholders and timeframes. In terms of monetized benefits assessment, regulators typically require evaluation of several key categories. Direct system benefits form the foundation, including reduced losses and improved reliability metrics that can be directly quantified in monetary terms. These are complemented by avoided costs, such as deferred investments and reduced maintenance expenses, which must be carefully documented and justified. Market efficiency benefits represent another crucial category, encompassing reduced congestion and improved price signals that enhance overall economic efficiency of the system.

Environmental benefits pose a particular challenge in the monetary assessment, yet regulators increasingly require their inclusion. This involves not only carbon emission reductions but also broader environmental impacts that can be monetized through established methodologies. Socioeconomic benefits, including job creation and regional development impacts, round out the monetary assessment framework, though regulators often require conservative approaches to such broader benefit calculations.[2]

Beyond purely monetary considerations, modern regulatory frameworks mandate evaluation of non-monetary impacts through structured methodologies. Security of supply improvements must be systematically assessed, even when direct monetization proves challenging. System flexibility enhancement represents another critical non-monetary benefit, particularly relevant in the context of increasing renewable energy integration. Environmental impacts beyond carbon emissions, such as biodiversity effects and land use changes, require careful documentation and assessment. Social equity considerations and technology innovation potential complete the non-monetary evaluation framework, ensuring a comprehensive assessment of proposed investments.

Regulators increasingly emphasize the importance of long-term scenario analysis in the CBA framework. This approach requires grid operators to evaluate proposed investments against multiple possible future scenarios, ensuring robustness across different potential energy transitions. The scenario analysis must consider various possible technology developments, policy changes, and market evolutions that could affect the value of proposed investments.

Coordination with National Energy Policy

The interface between policy and regulation requires coordination mechanisms that preserve the independence of both functions while ensuring effective alignment. Regular formal consultations between regulatory authorities and policy bodies provide the foundation for this coordination. These consultations enable necessary information exchange and alignment of objectives.

The translation of high-level objectives into specific planning criteria and requirements necessitates careful consideration of technical feasibility, economic efficiency, and practical implementation challenges. Regulators must establish quantifiable targets that align with policy goals while remaining achievable within technical and economic constraints. Monitoring and reporting frameworks should track progress towards these targets while providing feedback on implementation challenges.

Long-term planning alignment represents a particular challenge in coordination between general energy policy and regulation. Regulatory frameworks must ensure that grid development plans support both immediate

[2] Brattle Group, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, 2021, https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf

needs and long-term policy objectives without compromising system reliability or economic efficiency. Investment evaluation criteria should reflect policy priorities while maintaining focus on technical and economic merit. Innovation initiatives must align with national energy strategies while preserving technology neutrality and competitive pressure.

The coordination process requires careful attention to institutional boundaries and relationships. Regular policy-regulatory dialogue should occur without compromising regulatory independence or creating confusion about decision-making authority.[3] Documentation of policy influence on regulatory decisions should be transparent, allowing stakeholders to understand how various factors were weighted in final determinations. When conflicts arise between policy objectives and regulatory requirements, clear processes should guide their resolution while maintaining regulatory stability and predictability.

STAKEHOLDER ENGAGEMENT AND TRANSPARENCY

The regulatory framework for stakeholder engagement must establish a clear, multi-stage process that goes beyond simple consultation. This process begins with comprehensive stakeholder identification and mapping, ensuring all affected parties have appropriate opportunities for input. Early engagement should focus on methodology and assumptions, allowing stakeholders to influence the fundamental approach to planning before specific proposals are developed.

Formal consultation on specific proposals represents the core of the engagement process, but it must be supported by ongoing dialogue mechanisms. Regular stakeholder forums and working groups provide opportunities for detailed technical discussions and help build shared understanding of complex issues. The engagement process should maintain continuous dialogue mechanisms for key stakeholders, ensuring that important concerns can be addressed as they arise rather than only at formal consultation points.

Information access forms a crucial component of the regulatory framework for stakeholder engagement. Stakeholders must receive access to detailed planning assumptions and methodologies, allowing them to understand and critique the basis for proposed investments. Cost-benefit analysis results should be presented transparently, with clear documentation of key assumptions and methodologies. Environmental and social impact assessments must be made available in accessible formats, along with clear explanations of how alternatives were considered and evaluated.

The integration of stakeholder input requires formal processes that go beyond simple documentation. Regulators should require grid operators to demonstrate how stakeholder input influenced final decisions, including explicit explanations when stakeholder proposals are not adopted. This process should include regular assessment of stakeholder satisfaction and engagement effectiveness, with requirements to adapt engagement processes based on experience and feedback.

Many national cases underline the relevance of stakeholder engagement; among them, a best practice is given by the Australian Energy Regulator with the Regulatory Investment Test, that provide an example of how transparency requirements can be structured, requiring detailed public documentation of planning processes and investment decisions while protecting commercially sensitive information.

In conclusion, energy regulators play a vital role in ensuring that grid planning and investment serve the public interest while enabling necessary system development. Their role is not to substitute for grid operators in technical planning, but rather to establish frameworks that promote efficient, transparent, and forward-looking

[3] Brunekreeft, G (2023), *Improving regulatory incentives for electricity grid reinforcement*, Study for Autoriteit Consument en Markt, Constructor University, https://www.klimaatweb.nl/wp-content/uploads/po-assets/867722.pdf

grid development. Success in this role requires careful balance between oversight and flexibility, allowing grid operators to innovate while ensuring that investments remain prudent and cost-effective.

2. Regulatory Framework for Grid Planning Evaluation: An Overview

The evaluation of long-term grid plans[4] stands as one of the most critical responsibilities entrusted to National Regulatory Authorities in the energy sector. As power systems evolve to meet the challenges of the energy transition, the complexity of this task has grown exponentially. Modern grid planning must address not only traditional concerns of reliability and efficiency but also incorporate new paradigms brought about by technological advancement and societal changes.

The fundamental challenge facing regulatory authorities lies in developing and implementing assessment frameworks that can effectively evaluate both conventional infrastructure needs and emerging technological solutions. These frameworks must be sufficiently robust to ensure system reliability while remaining flexible enough to accommodate innovation and market evolution. Consider, for instance, how the increasing penetration of renewable energy sources has transformed what were once relatively straightforward planning exercises into complex energy scenarios, involving intermittent generation, storage requirements, and dynamic demand patterns.

Network planning assessment has evolved significantly from its traditional focus on meeting peak demand through supply-side solutions. Today's planning process must consider a rich tapestry of interrelated factors that influence both demand and supply dynamics. The assessment of demand projections, for instance, now requires consideration of how emerging technologies and changing consumer behaviours reshape consumption patterns.

Consider the case of urban load growth in developing economies. Traditional planning approaches might have simply extrapolated historical trends, adjusting for expected population and economic growth. Modern planning must account for how factors such as distributed generation, electric vehicle adoption, and energy efficiency improvements might fundamentally alter the relationship between economic growth and electricity demand. The experience of several Asian megacities demonstrates this complexity, where rapid urbanization has coincided with technological leapfrogging, leading to demand patterns that deviate significantly from historical models.

Supply scenario development has likewise grown more sophisticated. Planners must now consider not only the adequacy of generation capacity but also the system's ability to accommodate highly variable renewable energy sources. The North Sea region provides an instructive example, where the massive deployment of offshore wind power has necessitated fundamental reconsideration of transmission planning approaches. Rather than simply connecting generation to load centers, planners must now envision integrated systems that can manage power flows across multiple jurisdictions while maintaining system stability under varying weather conditions.

[4] In the European Union, at transmission level the long-term grid plans are called Ten Year National Development Plans (TYNDPs).

2.1 Fundamental Elements of Network Planning Regulatory Assessment

Network planning assessment begins with the careful evaluation of methodological approaches and underlying assumptions. Regulatory authorities must examine the TSOs' demand projections, which should incorporate both macroeconomic factors like GDP growth and sector-specific energy consumption patterns. For example, the emergence of data centres in certain regions might require specific attention due to their substantial and relatively inflexible power demands. Similarly, the growth of electric vehicle adoption requires careful consideration of both total energy demand and its temporal distribution.

Peak load projections must account for various scenarios, such as extreme weather events or simultaneous charging of electric vehicles. For instance, a heatwave coinciding with high industrial activity could create unprecedented demand peaks.[5] Demand-side management initiatives, such as time-of-use tariffs or industrial load shifting programs, should be incorporated into these projections to reflect their potential impact on peak demand.

Supply scenarios must address system adequacy across multiple timeframes, from seasonal to hourly variations. For example, a region with high solar penetration might need to plan for evening demand peaks when solar generation decreases, while areas with significant wind resources might need to consider seasonal wind patterns in their adequacy assessments.

2.2 Project Categorization and Technical Evaluation

The categorization of transmission projects represents a critical step in the evaluation process, as it provides a framework for assessing projects against appropriate criteria. Resilience projects, for instance, focus primarily on enhancing system security and reliability. These projects require evaluation frameworks that can quantify improvements in system performance under various contingency scenarios. The case of the Italy-Montenegro HVDC interconnector illustrates this approach, where project evaluation considered not only normal operating conditions but also system performance during disturbances and the contribution to black start capabilities.

Efficient expansion projects present a different set of evaluation challenges. These projects aim to meet growing demand while minimizing system losses and environmental impact. The evaluation must consider not only immediate needs but also long-term system evolution. Germany's SuedLink project exemplifies the complexity of modern expansion planning, where traditional considerations of capacity requirements must be balanced against environmental concerns, public acceptance, and the need for technological innovation.

Market functioning projects introduce yet another dimension to the evaluation process. These projects aim to reduce congestion and improve market integration, requiring assessment frameworks that can quantify economic benefits across multiple jurisdictions. The development of interconnectors in the Baltic region demonstrates how such projects can simultaneously serve multiple objectives, from enhancing energy security to facilitating renewable energy integration and market competition.[6]

[5] DSO Entity, "Good practices on Distribution Network Development Plans," 2024 https://eudsoentity.eu/wp-content/uploads/2024/09/DSO-Entitys-identified-good-practices-on-Distribution-Network-Development-Plans_Final.pdf

[6] https://www.eurelectric.org/in-detail/grid-synchronisation-and-energy-security-the-baltics-case/; https://www.regula.lt/en/Pages/Updates/2020/NERC-THE-AGREEMENT-ON-COST-ALLOCATION-FOR-BALTIC-SYNCHRONISATION-PROJECT-PHASE-II-IS-SIGNED-BY-LITHUANIAN,-LATVIAN,-ESTONIA.aspx

Infrastructure projects within the long-term plan framework fall into five distinct categories, each with specific evaluation criteria[7]:

Efficient Expansion Projects Address Demand Growth while Minimizing Losses

- An example might be upgrading an existing corridor from 220kV to 400kV to meet growing demand while reducing transmission losses.
- The evaluation would quantify both the increased capacity and the reduction in system losses, often measured in MWh/year

Strategically Planned Projects Align with National Energy Policies

- For example, offshore grid development to support wind energy might be evaluated not just on immediate needs but on its contribution to national renewable energy targets and long-term decarbonization goals.

Resilience Projects Focus on Security of Supply and Reliability

- For example, a new transmission line providing an alternative supply route to a major urban area would be evaluated based on its contribution to reducing the probability and impact of supply interruptions.
- The evaluation might consider how the project improves system performance during N-1 contingencies or extreme weather events.

Market Functioning Projects Aim to Reduce Congestion and Improve Regional Integration

- For instance, a new interconnector between two price zones would be evaluated based on its potential to reduce price differentials and increase trading opportunities.
- The assessment would include analysis of expected congestion reduction and increased social welfare through market integration.

Access Provision Projects Meet Specific Connection Needs

- Examples include grid extensions to accommodate new renewable energy zones or industrial developments.
- These projects would be evaluated based on their ability to efficiently integrate new generation or load while maintaining system stability.

2.3 Cost-Benefit Analysis of Grid Projects

The application of cost-benefit analysis to transmission projects has grown increasingly sophisticated as power systems have evolved. Modern CBA frameworks must account for a wide range of benefits, from traditional measures such as reduced congestion and losses to broader societal benefits such as reduced carbon emissions and enhanced energy security. The challenge lies in developing methodologies that can credibly quantify these diverse benefits while accounting for uncertainty in key variables.

[7] For 'Resilience Projects Focus on Security of Supply and Reliability' consult IEA (2020) Power system in transition, challenges and opportunities ahead for electricity security https://www.iea.org/reports/power-systems-in-transition

The experience of several European interconnector projects illustrates the complexity of modern CBA. These projects often generate benefits across multiple jurisdictions and stakeholder groups, requiring careful consideration of how benefits and costs should be *allocated*. The evaluation must consider not only direct economic benefits but also harder-to-quantify impacts such as enhanced security of supply and increased market competition.

Cost-Benefit Analysis requires a comprehensive evaluation of both monetary and non-monetary impacts. For example, when assessing a new transmission line, direct benefits might include reduced congestion costs and lower system losses, while indirect benefits could include improved system reliability and increased renewable energy integration.

Practical examples of benefit quantification include:

- Calculating the value of lost load (VOLL) for reliability improvements,
- Quantifying market benefits through reduced generation costs (better competition where market is open),
- Estimating CO2 emission reductions from improved renewable integration,
- Assessing system stability improvements through dynamic simulation studies.

2.4 Risk Assessment in Infrastructure Planning

Risk assessment must consider various scenarios and their probabilities. For instance, a project's viability might be tested against different fuel price scenarios, varying renewable energy deployment rates, or different demand growth patterns. A concrete example would be testing how a proposed interconnector's business case holds up under different scenarios for cross-border price differentials.

The evaluation of risk in transmission infrastructure projects has become increasingly complex as power systems face new challenges and uncertainties. Modern risk assessment frameworks must consider not only traditional technical and financial risks but also emerging challenges related to climate change, cybersecurity, and rapidly evolving technology. This evolution in risk assessment approaches reflects a growing understanding that transmission infrastructure must be resilient to a wide range of potential futures.

Consider, for instance, the challenge of assessing climate-related risks to transmission infrastructure. Traditional approaches might have focused primarily on immediate weather-related risks such as wind loading or ice accumulation. Modern risk assessment must consider how changing climate patterns might affect both infrastructure requirements and system operation over decades. The experience of transmission operators in coastal regions demonstrates this evolution, as rising sea levels and increasing storm intensity force a fundamental reconsideration of infrastructure design and location decisions.

Technology risk represents another critical dimension of modern infrastructure planning. The rapid evolution of power electronics, energy storage, and control systems creates both opportunities and challenges for transmission planners. Projects must be evaluated not only against current technological capabilities but also with consideration for how technological evolution might affect their value over time. In particular, the case of HVDC projects illustrates this challenge well, as advancing technology continues to expand the range of possible applications while potentially rendering earlier design choices suboptimal.

2.5 Stakeholder Engagement in Modern Infrastructure Planning

The evolution of stakeholder engagement in transmission planning reflects broader changes in societal expectations regarding infrastructure development. Modern engagement frameworks must go beyond simple information dissemination to create meaningful opportunities for stakeholder input and participation in decision-making processes. This evolution requires regulatory authorities to develop new approaches to stakeholder identification, engagement, and feedback incorporation.

The experience of major transmission projects in densely populated regions demonstrates the critical importance of effective stakeholder engagement. Consider the case of underground cable projects in central Europe, where early and comprehensive stakeholder engagement has proven essential to project success. These projects show how engagement frameworks must adapt to address not only traditional stakeholder concerns about environmental and visual impacts but also emerging issues related to electromagnetic fields, property values, and local economic development.

Digital technologies have transformed the possibilities for stakeholder engagement while creating new challenges for regulatory authorities. Online platforms and social media enable broader participation in planning processes but require careful management to ensure constructive dialogue and meaningful input. The experience of several TSOs in conducting virtual consultations during recent years has demonstrated both the potential and limitations of digital engagement tools.

The stakeholder engagement process requires a structured approach with clear timelines and responsibilities. A typical engagement process might include:

Pre-consultation phase

- Publication of consultation documents in accessible formats-
- Early engagement with key stakeholders such as generators, large consumers, and environmental groups
- Preparation of simplified explanatory materials for non-technical audiences

Consultation phase

- Online consultation platforms for written submissions
- Public workshops and technical sessions
- Specific engagement with affected communities and local authorities
- Expert roundtables on technical aspects

Post-consultation phase

- Public workshops and technical sessions
- Online consultation platforms for written submissions
- Specific engagement with affected communities and local authorities

2.6 Regional Coordination

The increasing interconnectedness of power systems has made regional coordination an essential element of transmission planning. This coordination must occur at multiple levels, from technical harmonization of planning standards to agreement on cost allocation methodologies for cross-border projects.[8] The experience

[8] IRENA, insights on planning for power systems regulators (2018) https://www.irena.org/publications/2018/Jun/Insights-on-planning-for-power-system-regulators

of European power system integration provides valuable lessons in how such coordination can be achieved while respecting national sovereignty and protecting consumer interests.

The development of the North Seas Energy Cooperation offers an instructive example of regional coordination in practice. This initiative demonstrates how multiple jurisdictions can work together to plan and implement complex infrastructure projects that serve both national and regional objectives. The coordination framework addresses not only technical and economic aspects of project development but also environmental concerns and stakeholder interests across multiple countries.

Cost allocation for regional projects presents particular challenges that require sophisticated evaluation frameworks. The traditional approach of allocating costs based on territorial boundaries becomes increasingly inadequate as power flows become more complex and benefits more widely distributed. Modern frameworks must consider how project benefits accrue across jurisdictions and stakeholder groups, often requiring innovative approaches to ensure fair allocation of costs and benefits.[9]

2.7 The Role of Regulatory Oversight in Project Implementation

Effective regulatory oversight of project implementation requires frameworks that can track progress, identify potential issues, and facilitate appropriate interventions when necessary. This oversight must balance the need for project certainty with the flexibility to adapt to changing circumstances. The experience of major infrastructure projects across multiple jurisdictions demonstrates the importance of clear frameworks for progress monitoring and issue resolution.

Consider the case of major HVDC interconnector projects, where implementation often spans multiple years and jurisdictions. Regulatory oversight must address not only traditional project management concerns such as cost control and schedule adherence but also evolving challenges related to technology selection, environmental compliance, and stakeholder management.

Modern regulatory frameworks must also consider how project implementation relates to broader system development objectives. This requires mechanisms for regular review and adjustment of implementation plans to ensure alignment with evolving system needs and policy objectives. The experience of renewable integration projects in particular demonstrates the importance of adaptive regulatory frameworks that can accommodate changing circumstances while maintaining project momentum.

These evolving challenges in transmission planning and implementation highlight the need for continued development of regulatory frameworks and evaluation methodologies. As power systems continue to evolve, regulatory authorities must maintain a delicate balance between ensuring system reliability together with cost-effectiveness and enabling innovation.[10]

The success of this endeavour will play a crucial role in enabling the transition to a more adequate, sustainable and resilient energy future.

[9] Within the European Union, guidelines for Cross-Border Cost Allocation (CBCA) decisions have been issued by ACER (the European Agency for Cooperation of Energy Regulators): https://www.acer.europa.eu/electricity/infrastructure/projects-common-interest/cross-border-cost-allocation

[10] Ember, Putting the mission in transmission: Grids for Europe's energy transition, 2024 https://ember-energy.org/app/uploads/2024/10/Grids-for-Europes-Energy-Transition-Report-1.pdf

3. Grid Plan Assessment: Summary of the Survey Results

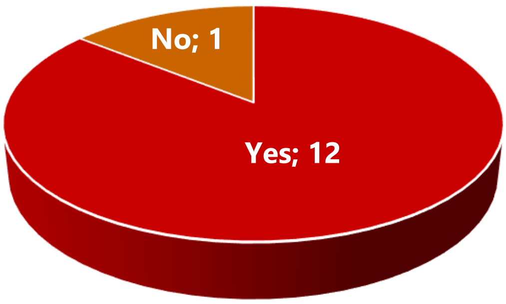
The EMER Committee distributed a questionnaire to its members and collected 13 answers (from the regulators of Albania, Armenia, Austria, Georgia, Hungary, Latvia, Lithuania, Moldovia, North Macedonia, Oman, Romania, Saudi Arabia and Türkiye). In this section there is a summary of the part of the questionnaire dedicated to grid plan regulatory assessment.

3.1 The Assessment Process of Network Development Plans

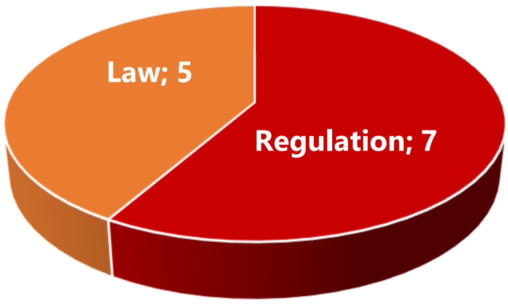
The survey focused on the regulatory evaluation process of electricity network development projects at both transmission and distribution levels across multiple jurisdictions. The analysis reveals several key findings regarding the formalization and structure of these processes.

Process Formalization and Legal Basis

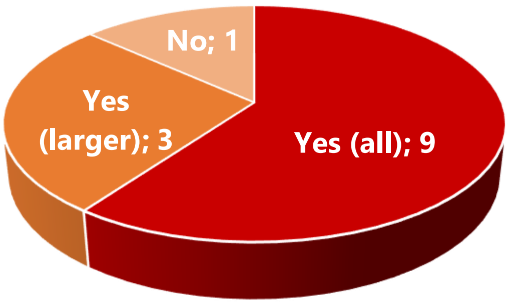
Most responding countries have well-structured and formalized processes for evaluating grid investments, with requirements mostly set by the regulator. The table below summarizes the legal basis for these processes:



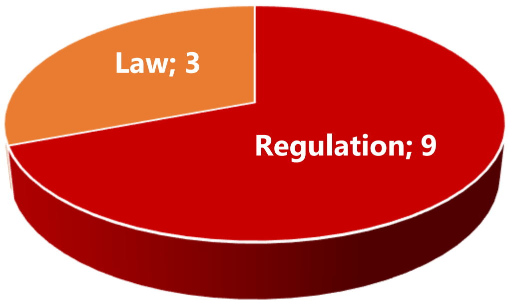
TSO Process Formalized



Legal Basis TSO Process



DSO Process Formalized



Legal Basis DSO process

Country	TSO Process formalized	Legal Basis TSO process	DSO Process formalized	Legal Basis DSO process
Albania	Yes	Regulation	Yes (all)	Regulation
Armenia	Yes	Regulation	Yes (all)	Regulation
Austria	Yes	Law	No	-
Georgia	Yes	Law	Yes (all)	Regulation
Hungary	Yes	Law	Yes (all)	Law
Lithuania	Yes	Law	Yes (all)	Law
Latvia	Yes	Law	Yes (larger DSOs)	Law
Moldova	Yes	Regulation	Yes (all)	Regulation
N. Macedonia	Yes	Regulation	Yes (all)	Regulation
Oman	Yes	Regulation	Yes (all)	Regulation
Romania	Yes	Regulation	Yes (larger DSOs)	Regulation
Saudi Arabia	Yes	Regulation	Yes (larger DSOs)	Regulation
Türkiye	No	-	Yes (all)	Law

Figure 1: Formalization of the assessment process for grid plans at transmission and distribution level

Regulatory Approval Process

The survey reveals that in almost all jurisdictions, the regulator has direct approval authority over grid investment plans:

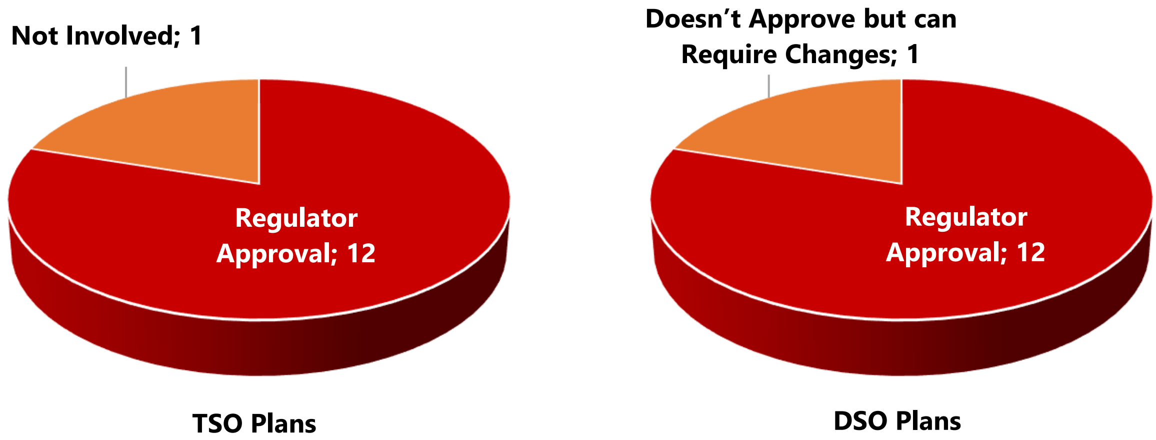


Figure 2: Role of regulators in approval process of grid plans

Content and Transparency of Plans

The plans are prepared by the network operators, and usually contain information and data on development projects, including cost and timeline, and sometimes on other topics like new interconnections coordinated with other neighbouring operators. Most of the times, the operators make their network plans public together with the main data for sake of transparency and public discussion. At the end of the evaluation process the regulator approves the plans, or in less cases provides an opinion to the competent Ministry for final approval; in some countries this role is differentiated between transmission and distribution.

The development plans typically contain detailed information about:

- Infrastructure development projects
- New interconnections coordination
- Technical parameters and specifications
- Cost estimates and implementation timelines
- Load forecasts and system analyses
- Integration plans for renewable energy sources

Almost all countries make their transmission network plans publicly available (11 out or 13), though with varying levels of data accessibility:[11]

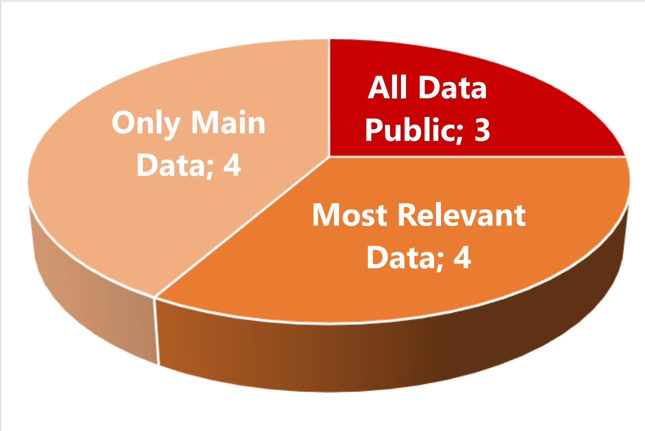


Figure 3: Public availability of data of publicly available grid plans
(in 2 cases out of 13, grid plans are not publicly available)

STAKEHOLDER CONSULTATION

Consultation of the parties is foreseen in the vast majority of cases and there are different methods in terms of length of the consultation period, number and types of participants, availability of the results of the consultation. In some cases, like North Macedonia, the Regulator may organize a Public Session or may pass decisions in General Session which is open to the public.

The consultation process varies significantly across jurisdictions, but most countries have formal requirements:

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[11] Although there is not a clear definition, we assume the following:

1. "main data" are typically capacity (MW), network lenght (km) and overall investment cost;
2. "most relevant data" enter in more detail, like expected energy flows, estimated benefits of the project in different scenarios, reliability and other technical and economic data of each project;
3. "all data" means all simulations are publicly available including for instance, hourly datasets.

Consultation Aspect	Common Approaches
Formal consultation before approval	For TSO plans: 10/13 For DSO plans: 11/13
Duration	30-90 days typical
Participants	System operators, government agencies, industry stakeholders, consumer groups
Methods	Written submissions, public hearings, stakeholder conferences
Transparency	Results typically published, though level of detail varies

Table 1: Public consultations: characteristics

Planning Frequency and Updates

The frequency of updating the plans shows some variations: it can be annual or biennial, i.e. every two years. In some countries of the European Union, the update of the development plan of the transmission network can be biennial in synchronization with the ten-year network development plan (TYNDP) of the European transmission network that is prepared every two years according to the European regulation by the body that associates the European TSOs (ENTSO-e).

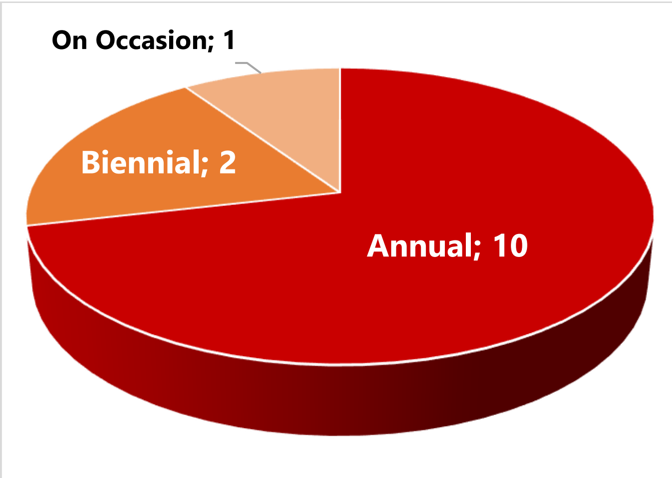

Figure 4: Frequency of update of transmission grid plans

3.2 Regulatory Templates for Grid Plans

Most countries have formalized templates for TSO plans, with slightly less standardization for DSO plans.

Content requirements are generally more extensive for TSO plans, particularly regarding system-wide impacts and cross-border considerations.

Common core elements across all jurisdictions include:

- Infrastructure description
- Cost estimates
- Implementation timelines
- Technical parameters

There is a trend towards increasing standardization while maintaining flexibility for local conditions and emerging needs (like smart grid requirements for DSO plans).

Overview of Template Requirements

Country	TSO Template Approved	DSO Template Approved	Template Format
Albania	No	No	Company defined
Armenia	No	No	Company defined
Austria	Yes	No	Regulator defined (TSO only)
Georgia	Yes	Yes	Regulator defined
Hungary	Yes	Yes	Regulator defined
Latvia	Yes	Yes	Regulator defined
Lithuania	Yes	Yes	Regulator defined
Moldova	Yes	Yes	Regulator defined
North Macedonia	Yes	Yes	Regulator defined
Oman	Yes	Yes	Regulator defined
Romania	Yes	Yes	Regulator defined
Saudi Arabia	Yes	Yes	Regulator defined
Türkiye	No	Yes	Regulator defined (DSO only)
Summary	**Yes: 10/13** **No: 3/13**	**Yes: 10/13** **No: 3/13**	

Table 2: Regulatory templates for grid plans

Content Requirements Comparison: TSO Plans

The survey does not allow to have a full picture of the content of TSO plan requirements, however it's clear that some common points are shared by all the countries:

- Network Infrastructure Description
- Demand and supply forecast and RES penetration
- Projects planned in the next 5 to 10 years
- Investments to be executed in the next 3 years
- Cost estimates and expected implementation timelines.

Other issues are less common:

- Investment Categorization (signalled only in 3 cases out of 13)
- Environmental impact
- Impact on transmission tariff
- Project cost breakdown
- Benefit quantification
- Economic efficiency indicators
- Cross-border benefit analysis.

3.3 Cost-Benefit Analysis in Grid Investment Evaluation

The survey reveals significant variation in how Cost-Benefit Analysis is implemented across jurisdictions:

Country	CBA Status	Methodology Definition	Methodology Owner
Albania	Ad hoc	Not clearly defined	Network operators
Armenia	-	Not used for power grid investments	-
Austria	No CBA (*)	Used only for PCIs	Entso-e
Georgia	Yes	Regulator sets the methodology	Regulator
Hungary	No CBA (*)	Used only for PCIs	Entso-e
Latvia	No CBA (*)	Used so far only for PCIs; planned for 2025	(Regulator in the next future)
Lithuania	Yes	Regulator sets the methodology	Regulator
Moldova	Yes	Defined in regulation, according to investment categorization	Regulator
North Macedonia	Yes	Based on project cost, but not structured method	Network operators
Oman	Yes	Requirements of CBA methodology are set by regulator	TSO proposes / regulator approves
Romania	Ad hoc	Not clearly defined	Network operators
Saudi Arabia	Ad hoc	Not clearly defined	Network operators
Türkiye	-	Not used for power grid investments	-

(*) Entso-e CBA methodology used for Projects of Common Interest (PCIs)

Table 3: Cost-benefit analysis

Benefits Categories Considered

Analysis of investment benefits varies significantly across jurisdictions that use CBAs or other methods. Below is a breakdown of which benefits are considered, based on available answers in the survey:

Benefit Category	Number of countries
Network losses variation	6
RES integration	5
Energy Not Supplied (ENS)	4
Effects on generation costs	4
Dispatching cost reduction	3
CO2 emissions reduction	2
Socio-economic welfare	1

Table 4: Benefit categories considered in CBA (multiple answer allowed)

Cost Components

Treatment of costs also shows variation:

Cost Category	Number of occurrences
Investment costs only	2
Investment + operating costs	3
Total costs including compensation	2
Not specified	1

Table 5: Cost-categories considered in CBA (limited number of respondents)

Thresholds for CBA Application

The survey shows also large differences in economic thresholds set to require a deeper economic analysis of grid projects proposed by TSO/DSOs.

Country	Threshold Value	Basis
North Macedonia	€100,000	Economic efficiency required above this threshold
Georgia	5M GEL (≈€1.7M) for TSO, 1M GEL (≈€0.33M) for DSO	Detailed analysis required above this threshold
Oman	20M Omani Rials (≈€50M) for transmission projects	This threshold applies to Project Delivery Incentive scheme
Lithuania	Electricity: €3.5 M for TSO, €1.5 M for DSO	Assessment based on project category system
Saudi Arabia	TSO/DSO conduct CBA for all projects.	Regulator review projects based on random sampling; above 500 M SAR (≈€125M) transmission projects are automatically selected
Latvia, Hungary, Austria	No threshold specified	CBA only for cross border PCIs
Romania	No threshold specified	Sample analysis of at least 20% of projects, totalling 30% of investment value
Moldova	No threshold specified	Assessment based on project category system (8 categories)
Albania	No threshold specified	Network operators perform ad hoc economic analysis
Armenia, Türkiye	No threshold specified	No CBA required for grid investments

Table 6: Thresholds for CBA

Two case studies about regulatory mandate for long-term DSO planning (Armenia) and detailed grid plan assessment (Georgia) are described in Chapter 5, respectively paragraph 5.1 and 5.3.

Implementation Challenges

Common issues reported in the survey are summarised in the following table:

1. Methodology Issues	3. Resource Constraints
• Lack of standardized approaches • Difficulty in quantifying certain benefits • Inconsistent application across projects	• Limited analytical capacity • Time constraints • Technical expertise requirements
2. Data Limitations	**4. Coordination Challenges**
• Availability of reliable data • Forecasting uncertainties • Measurement of indirect benefits	• Cross-border project evaluation • Multiple stakeholder involvement • Regional benefit allocation

Figure 5: Implementation Challenges for CBA

First Conclusions on CBA

The analysis reveals significant variation in CBA approaches across jurisdictions, ranging from comprehensive frameworks to ad hoc applications. While some countries have developed sophisticated methodologies, others are still in early stages of implementation.

The trend seems toward more structured and comprehensive approaches, with increasing attention to:

- Environmental benefits
- System-wide impacts
- Innovation potential
- Cross-border effects

Success factors include:

- Clear methodological frameworks, including clear categorization of projects, defined evaluation criteria, standardized templates
- Appropriate and significative thresholds
- Flexible application, considering different requirements by project size
- Stakeholder engagement

Future development should focus on:

- Capacity building and strong monitoring systems
- Process and methodology improvement, including progressive enlarging of multiple benefit categories and including qualitative factors aside quantitative ones
- Enhanced stakeholder engagement

3.4 Scenarios and Uncertainty Analysis

Sensitivity analyses of some essential parameters are used above all for short-term forecasts (those relating to the “study year” between 3 and 5 years) with reference, for instance, to parameters such as demand estimates, commodity prices and renewable penetration estimates.

Scenario analyses, which repeat the technical-economic analysis or the cost/benefit analysis in different scenarios, even contrasting ones, to assess the effects of uncertainty on the future, are not widely used.

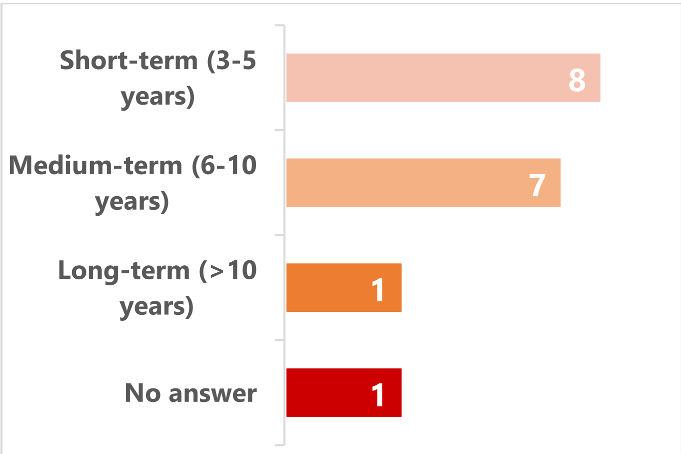

Figure 6: Planning horizons (multiple response allowed)

As for sensitivity analysis, countries commonly focus on the following parameters:

- Demand forecasts
- Renewable energy penetration
- Commodity prices
- Import/export scenarios

In scenario development, the use of multiple scenarios (or so-called "contrasting" scenarios) is not widespread:

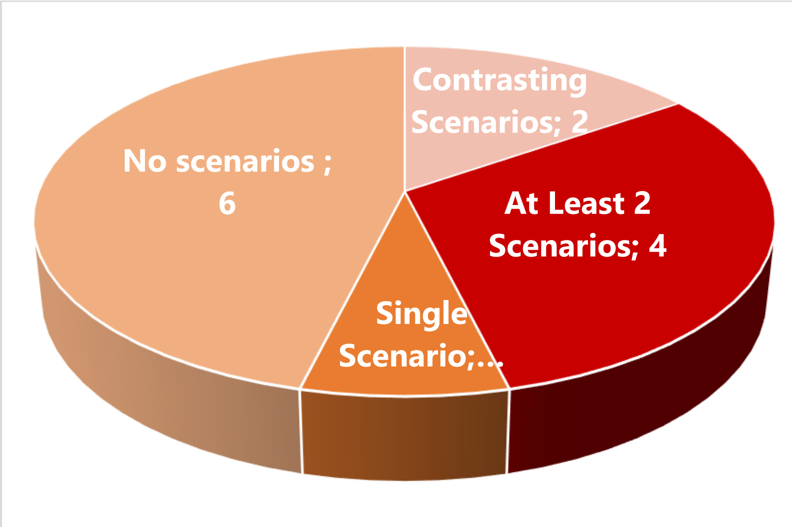

Figure 7: Use of scenarios

Furthermore, there is only one case (Austria) in which such scenarios are developed jointly between electricity and gas TSOs, being typically developed separately by the system operators of the two sectors (different from each other). In few other cases it is referred a "partial" consistency among electricity and gas scenarios. This indicates a significant gap in the coordination between electricity and gas planning across most countries, that highlights an area for improvement.

3.5 Stakeholder Engagement

Although in some countries there is no legal obligation to publicly consult interested parties on the network plans presented by transmission and distribution operators, in fact this practice is common in practically all countries.

Written comments are collected, also with digital tools, and conferences and discussion seminars can be organised. However, no practices of particular relevance are reported.

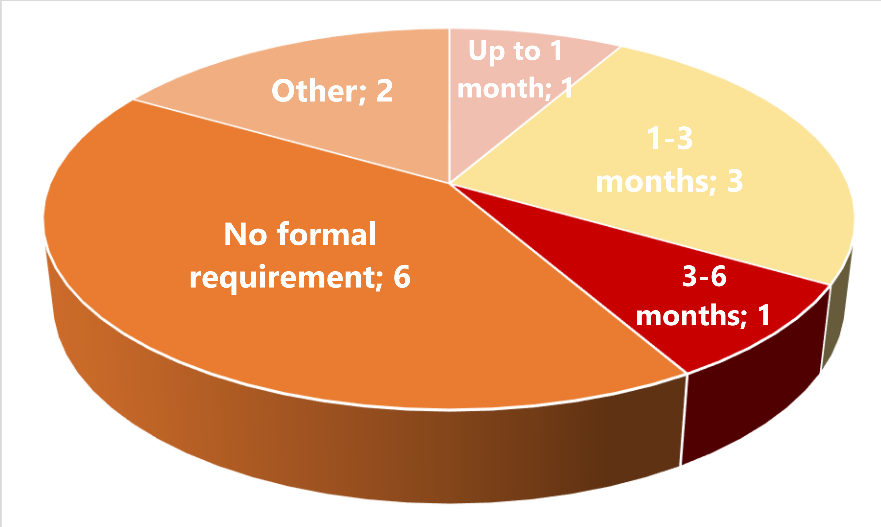

Figure 8: Duration of consultations

Most common engagement methods include written/digital submissions; less common ones:

- Stakeholder conferences
- Public hearings

Among the reported problems, the most frequent is the limited participation in the consultation procedures from system users side.

4. Incentives for investment execution: summary of the survey results

In this section there is a summary of the part of the questionnaire dedicated to financial planning and tariff treatment of planned investments, including incentives for investment execution. On top of the collected answers to the survey, five case studies have been collected from Armenia, Georgia, North Macedonia and also from Member organisation like France and Rhode Island (US) that are not included in the survey; all case studies are collected in Chapter 5.

4.1 Financial Planning and Tariff Treatment

A section of the survey focuses on how regulators evaluate and ensure the financial viability of planned grid investments. This analysis examines how different jurisdictions approach investment financiability, from initial assessment to tariff reflection, revealing significant variations in regulatory practices while highlighting important common principles.

The survey reveals that most jurisdictions require some form of financial substantiation before approving grid investment projects:

Country	Financial Substantiation Required	Type of Information Required
Albania	Yes	Feasibility studies
Armenia	No	TSO not required to demonstrate financial resources
Austria	Yes	Medium-term investment planning
Georgia	Yes	Documentation of financial sources and relevant information
Hungary	No	Approving an investment in NDP does not result in automatically approving the investment costs in tariff. TSO provides information but formal substantiation not required
Latvia	Yes	Tabular forms with sources of financing
Lithuania	Yes	Sources of financing and financial appraisal
Moldova	Yes	Sources of finance for each project
N. Macedonia	Yes	Data on planned investments with financing sources
Oman	Yes	Information provided during price control review
Romania	No	TSO provides information but formal substantiation not required
Saudi Arabia	No	TSO provides all data via a single process (Revenue Requirement Determination)
Türkiye	No	Regulators not involved with financial sources, but monitor financial ratios of network operators
SUMMARY	**Yes: 9/13** **No: 4/13**	

Table 7: Financial viability and information required

A good majority position (9 out of 13 countries) indicates that financial viability is generally considered as a prerequisite for project approval, although in some cases the approval of the grid plan assessment and approval is fully distinct from the financial justification of investments.

Investment Recognition in Tariffs

How and when investments are reflected in tariffs shows significant variation:

Investment Recognition Mechanism	Number of Countries	Countries
At commissioning/entry into operation	5/13	Albania, Armenia, Hungary, Romania, Saudi Arabia, Moldova
During construction period	2/13	Austria
At moment of investment approval	4/13	Georgia, N. Macedonia, Oman, Türkiye
Other	2/13	Latvia, Lithuania

Table 8: Recognition in tariff of investments

Different approaches to when investments enter the tariff basis reflect different philosophies about risk allocation among regulators. It's important to say also that in cases of early recognition (at approval), ex post adjustments are foreseen in cases of delay.

A case of anticipated recognition in tariff as "ad hoc incentive" for investments is described in Chapter 5, paragraph 5.4 (North Macedonia).

Strengths and Weaknesses

Based on respondents' comments, key strengths and weaknesses include:

Reported Strengths	Reported Weaknesses
• Stable regulatory frameworks: providing investment certainty • EU funding opportunities: supporting critical projects • Clear efficiency criteria: ensuring value for money • Additional returns: encouraging priority investments	• Implementation gaps: low realization rates of approved investments • Forecasting challenges: inflation impacts on investment costs • Financing barriers: particularly for larger projects • Tariff impact concerns: balancing investment needs with consumer affordability

Figure 9: Strength and Weaknesses of Investment Framework

As a whole, the analysis suggests that while basic principles are widely shared, there remains significant room for cross-jurisdictional learning and possible harmonization in approaches to grid investment financiability, particularly regarding implementation monitoring and risk allocation.

4.2 Incentives for Timely and Efficient Investment Execution

Delays in grid investment projects can have significant negative impacts on system development, renewable energy integration, as well as increase in project costs impact the overall economic efficiency. Traditional regulatory approaches, which focus primarily on cost recovery, often provide insufficient incentives for timely and efficient project completion. This has led a few regulators to develop specific mechanisms aimed at encouraging on-schedule and on-budget project execution.

Country	Formalized control of timely execution	Timeliness Incentive/penalty	Efficiency control and incentive/penalty
Albania	No	No	No
Armenia	No	No	Yes
Austria	No	Yes (bonus & penalty)	Yes (standard costs)
Georgia	Yes	No	Yes (assessment system)
Hungary	Yes	No	No
Latvia	No	Yes (penalty only)	No
Lithuania	Yes	Yes (penalty only)	Yes (expert assessment)
Moldova	No	No	No
N. Macedonia	No	Yes (penalty only)	No
Oman	Yes	Yes (penalty only)	Yes (ex post assessment; possible RAB reductions)
Romania	No	No	Yes (output-based)
Saudi Arabia	Yes	No	No
Türkiye	Yes	Yes (bonus & penalty)	Yes (unit cost approach)
SUMMARY	**Yes: 6/13** **No: 7/13**	**Yes (bonus & penalty): 2/13** **Yes (only penalty): 4/13** **No: 7/13**	**Yes (various means): 6/13** **No: 7/13**

Table 9: Regulatory mechanisms for timely and efficient execution

INCENTIVE MECHANISMS: MOST RELEVANT CASES

THE OMAN PROJECT DELIVERY INCENTIVE: A REGULATORY FRAMEWORK FOR TIMELINESS OF EXECUTION

The Project Delivery Incentive (PDI) scheme implemented in Oman represents the most sophisticated approach to timeliness incentives among surveyed jurisdictions. The scheme applies to major transmission projects (those exceeding 20 million Omani Rials, which equals approximately 50 million euro) and incorporates several innovative features.

First, the scheme evaluates project progress at two critical milestones: the project awarding stage and the project commissioning stage. This dual assessment recognizes that delays can occur at different points in the project lifecycle and creates incentives for maintaining schedules throughout the whole lifecycle of the project.

Second, the regulatory mechanism incorporates reasonable deadbands to acknowledge that some delays are inevitable. These include two months at the awarding stage, two months at the commissioning stage, and four months total across the project lifecycle. This approach prevents penalties for minor delays while maintaining pressure for overall timely delivery.

Third, the scheme employs a non-symmetrical approach with carefully calibrated penalties. The maximum penalty is capped at either 10% of project cost or 3.5% of TSO business revenues, whichever is lower. Penalties are staged, with 2% for awarding delays and up to 7% for commissioning delays. The framework also includes a deferred penalty mechanism for awarding delays, recognizing the interconnection between project phases.

Fourth, the framework includes clear provisions for legitimate delays, including force majeure events, supply chain disruptions, government decisions, and natural disasters. This comprehensive approach could prove effective in maintaining project schedules while providing reasonable accommodation for legitimate delays.

Finally, the Omani regulator (APSR) undertakes ex-post capex efficiency assessment and RAB reductions in case of inefficiencies during the price control review for both transmission and distribution.

THE AUSTRIAN APPROACH: PROMOTING COST-EFFECTIVE DELIVERY

Austria has developed a multi-faceted approach to efficiency incentives that combines several key elements. The system begins with standard cost benchmarking, which provides a clear baseline for efficiency assessment. Projects are evaluated against these metrics to ensure cost-effectiveness.

The Austrian model also incorporates innovation incentives through special provisions that encourage projects improving system efficiency. Additional returns are available for efficiency-enhancing projects, with specific focus on reducing redispatching costs and supporting innovative technical solutions.

Furthermore, the framework includes specific incentives for projects that facilitate renewable energy integration, recognizing the broader system benefits of such investments. This multi-dimensional approach encourages both traditional cost efficiency and broader system improvements.

Finally, a bonus/malus is envisaged for timely or delayed execution.

THE ROMANIAN MODEL: PREMIUM ON TOP OF REGULATED RATE OF RETURN

Romania has implemented a system of efficiency incentives built around differentiated returns. The system includes categorized incentives, with different types of investments receiving varying incentive levels. The base rate of return can be enhanced by a 0.5% premium for qualifying projects, with special consideration for EU co-financed projects and additional returns for modernization initiatives.

The Romanian approach places particular emphasis on smart grid development through specific incentives targeting grid modernization. Premium returns are available for smart grid investments, with performance-based adjustments linked to development targets. These incentives are explicitly integrated with renewable energy objectives, creating a coherent framework for system advancement.

THE TURKISH APPROACH: UNIT COSTS AND QUALITY INCENTIVES

Türkiye has implemented a comprehensive framework for grid investment incentives that combines efficiency standards with performance-based rewards. The system centers on a predefined unit cost approach for distribution system operators, where the regulator establishes standardized costs for network components (transformers, lines, etc.) independent of actual expenditures.

This unit cost methodology serves multiple objectives. First, it provides regulatory certainty by establishing clear cost expectations for both the regulator and network operators. Second, it prevents excessive spending by capping cost recovery at the predetermined unit values. Third, it simplifies the regulatory evaluation process by reducing the need for detailed cost audits of each individual project.

The framework further incorporates a timing incentive mechanism through both penalties and bonuses. Distribution system operators must achieve at least 65% of their annual approved investment budget, creating a clear minimum threshold for implementation. Additionally, the system employs a sophisticated timing incentive where investments completed earlier than planned receive a financial advantage based on the WACC applied to the difference between actual and planned investment amounts. Conversely, late investments incur financial penalties using the same WACC-based calculation but in the opposite direction.

Türkiye's approach also integrates quality considerations into the investment evaluation process. The system directly links investment outcomes to service quality metrics through a quality factor component in tariffs. This creates an additional incentive for operators to prioritize investments that improve reliability and customer service, particularly those related to timely connection of new system users.

Even though France and Rhode Island (USA) did not participate in the survey, the incentive mechanisms used in those two jurisdictions for ensuring timely and efficient grid investment execution are described in Chapter 5, respectively paragraph 5.2 and paragraph 5.5.

4.3 Monitoring of Grid Investment Execution

Section 9 of the survey examines how regulators monitor the execution of approved grid investments. This analysis compares approaches across jurisdictions, revealing significant variations in monitoring frameworks, amendment procedures, inspection responsibilities, and overall monitoring focus. Understanding these differences provides insights into regulatory practices for ensuring effective implementation of approved investments.

Procedures for Amending Approved Investment Plans

Almost all jurisdictions have established procedures for making changes to approved investment plans, though the specific requirements vary considerably:

Country	Amendment Procedure	Key Features
Albania	Yes	Annual updates
Armenia	Yes	Changes to be submitted by November 1
Austria	Yes	Updates every two years
Georgia	Yes	10% value change threshold requires amendment
Hungary	No	Yearly planning is a cyclic exercise; annual NDP serves as monitoring exercise
Latvia	Yes	Evaluation for significant cost changes
Lithuania	Yes	10% cost deviation threshold
Moldova	Yes	Two amendment requests permitted annually (deadline: November 1)
N. Macedonia	No	No formal procedure reported
Oman	Yes	Internal gate process for variations. If changes are significant, TSO re-submits the project and it is reviewed by regulator
Romania	Yes	Amendments allowed until October 1; 80% of previous projects must remain

Country	Amendment Procedure	Key Features
Saudi Arabia	Yes	If changes are beyond certain ranges, TSO re-submits the project and it is reviewed
Türkiye	Yes	Approval is required for budget revisions
SUMMARY	**Yes: 11** **No: 2**	

Table 10: Procedures for amending the grid plan

The most structured approaches include specific thresholds (e.g., 10% cost deviation in Georgia and Lithuania) or clear timing windows for amendments (e.g., November 1 deadline in Armenia and Moldova).

MONITORING FRAMEWORKS

Regulatory appro6aches to monitoring investment execution show notable variation:

Country	Monitoring Framework	Monitoring Methods
Albania	No	-
Armenia	Yes	On-site inspections, documentation review
Austria	Yes	Quarterly infrastructure meetings
Georgia	Yes	On-site inspections, documentation review
Hungary	Yes	On-site inspections
Latvia	No	No formal monitoring framework
Lithuania	Yes	On-site inspections
Moldova	Yes	On-site inspections
N. Macedonia	No	No formal monitoring framework
Oman	Yes	Quarterly reports and on-site inspections
Romania	No	No formal monitoring framework
Saudi Arabia	Yes	Monitoring various items (delays, costs, KPIs, etc.)
Türkiye	Yes	Smart distance monitoring, on-site inspections
SUMMARY	**Yes: 9** **No: 4**	

Table 11: Monitoring framework

The data reveals that 8 out of 13 jurisdictions have established formal monitoring frameworks, with on-site inspections being the most common approach.

Responsible Bodies for Inspection

Different entities bear responsibility for investment verification across jurisdictions:

Country	Responsible Body
Albania	TSO/DSO self-audit
Armenia	Regulator
Austria	TSO/DSO self-audit
Georgia	Regulator
Latvia	No formal inspection
Lithuania	TSO/DSO self-audit
Moldova	Regulator
N. Macedonia	Technical inspection body
Oman	Regulator
Romania	TSO/DSO self-audit
Saudi Arabia	Regulator
Türkiye	Regulator

Table 12: Inspections on project execution

When inspections are conducted, they are split between regulator-led approaches (6 countries) and self-auditing by operators (4 countries), with one country using independent technical bodies.

Monitoring approaches range from simple verification of execution to comprehensive assessment of technical aspects, financial impacts, and realized benefits.

Strength and Weakness Analysis

Based on respondents' comments, key strengths and weaknesses include:

Reported Strengths	Reported Weaknesses
• On-site verification by regulatory staff • Clear amendment thresholds • Regular progress tracking • Comprehensive assessment parameters	• Limited resources for comprehensive monitoring • Absence of formal frameworks • Lack of standardized assessment criteria • Minimal verification of actual benefits

Figure 10: Strengths and Weaknesses of Monitoring Framework

The analysis suggests that while monitoring frameworks vary considerably, several common elements contribute to effectiveness. Clear amendment thresholds, balanced inspection responsibilities, and comprehensive assessment criteria emerge as key components of successful monitoring systems. As grid investments become increasingly complex, particularly with the integration of new technologies and renewable resources, robust monitoring frameworks will become even more critical for ensuring effective implementation.

5. Select National Case Studies

In this chapter, five case studies are presented in more detail. Two case studies are about grid plan assessment, one of which (Armenia, paragraph 5.1) especially dedicated at DSO long-term planning that is a new topic, and the other (Georgia, paragraph 5.3) dedicated at investment evaluation in broad sense. There are other two case studies on incentives, one from France for timely and efficient transmission investment execution (paragraph 5.2) and the other from North Macedonia about tariff recognition of investment (paragraph 5.4). The last case study is about Rhode Island (US) and has to do with both investment tariff recognition and monitoring.

5.1 Armenia: Case study on Regulatory Mandate for DSO Long-Term Planning

Armenia's DSO Investment Program and the Role of the Public Services Regulatory Commission[12]

This case study explores the modernization of Armenia's electricity distribution network, highlighting the strategic role of the Public Services Regulatory Commission (PSRC) in driving investments and reforms. With rising electricity demand, ageing infrastructure, and an increasing share of renewables, Armenia faces pressing challenges in ensuring grid reliability and sustainability. The PSRC's regulatory approach mandates long-term planning, tariff reforms, and performance monitoring to align utility investments with national energy goals. Drawing from international best practices, this study assesses the effectiveness of Armenia's regulatory tools and offers strategic recommendations for improving energy infrastructure and consumer outcomes.

Introduction

Armenia's energy sector has evolved significantly since independence, transitioning from a state-controlled system to a market-oriented framework. The country's energy mix, dominated by hydropower, nuclear and thermal generation, is increasingly incorporating renewable energy sources. However, the distribution network has struggled to keep pace with these changes, leading to inefficiencies and service quality issues.

Importance of Modernizing Distribution

Networks A well-functioning distribution network is crucial for economic growth, energy security, and environmental sustainability. A modernized network enhances grid resilience, facilitates renewable energy integration, and reduces technical and non-technical losses. Moreover, reliable power supply is a fundamental driver of industrial and commercial expansion, making distribution network efficiency a national priority.

1. ***Economic Growth and Competitiveness.*** A modern distribution network is a key enabler of economic development. Frequent outages and voltage fluctuations can disrupt industrial operations, leading to financial losses and reduced productivity. A reliable and well-maintained grid attracts investment by ensuring stable electricity supply for businesses and industries. In Armenia, where manufacturing and technology sectors are expanding, an upgraded distribution network is essential to sustaining this growth and improving economic competitiveness.
2. ***Energy Security and Grid Resilience.*** Energy security is a growing concern for Armenia, given its reliance on imported fuels for thermal generation. A modernized distribution network helps mitigate supply risks by improving energy efficiency and integrating local renewable sources. Advanced grid

[12] Case study provided by Davit Muradyan, Public Services Regulatory Commission (PSRC) of Armenia

technologies such as automated distribution management systems (ADMS) enhance grid resilience by enabling real-time monitoring, fault detection, and faster restoration of power during outages.

3. ***Renewable Energy Integration.*** Armenia has been expanding its renewable energy portfolio, particularly in small HPPs and solar. However, the existing distribution infrastructure presents challenges in accommodating variable energy sources. Without adequate upgrades, fluctuations in renewable energy generation can lead to grid instability. Modernizing the distribution network with smart grid technologies facilitates seamless integration of renewables, reducing curtailment and enhancing overall grid performance.

4. ***Reduction of Technical and Non-Technical Losses.*** High transmission and distribution losses, both technical (due to outdated infrastructure) and non-technical (such as electricity theft), are persistent issues in Armenia's power sector. Modern grid technologies, including advanced metering infrastructure (AMI) and smart transformers, help in accurately measuring and reducing losses. Countries like Georgia and Estonia have successfully reduced distribution losses through grid modernization efforts, providing a useful benchmark for Armenia.

5. ***Improved Service Quality and Consumer.*** Benefits Aging infrastructure leads to frequent power disruptions and voltage instability, impacting households and businesses alike. Consumers demand higher service quality, with greater reliability and transparency in energy usage. Smart grid solutions, including real-time monitoring and automated outage management, significantly improve service quality. Furthermore, digital customer engagement platforms can provide consumers with insights into their energy consumption patterns, promoting energy efficiency and demand-side management.

6. ***Environmental Sustainability and Emissions Reduction.*** Modernizing the distribution network also contributes to Armenia's climate goals by reducing greenhouse gas emissions. Energy-efficient infrastructure reduces losses and minimizes the need for additional power generation, thus lowering carbon footprints. The transition to a modern grid aligns with Armenia's commitments under the Paris Agreement and its goal to increase the share of renewables in the national energy mix.

Role of PSRC in Regulatory Oversight

The Public Services Regulatory Commission (PSRC) plays a vital role in ensuring that Distribution System Operators (DSOs) invest adequately in infrastructure while maintaining affordability and reliability. Through a structured regulatory framework, PSRC seeks to balance economic viability with consumer protection, ensuring efficient long-term network planning.

1. ***Investment Regulation and Long-Term Planning.*** One of PSRC's critical functions is to mandate and oversee long-term investment planning for DSOs. This ensures that infrastructure investments are not only cost-effective but also align with national energy goals. By requiring DSOs to submit detailed investment plans with technical and economic justifications, PSRC ensures that financial resources are directed towards projects that maximize reliability, efficiency, and sustainability.

2. ***Tariff Regulation and Consumer Protection.*** PSRC determines electricity tariffs based on a transparent methodology that considers operational costs, capital expenditures, and return on investment for DSOs. The regulatory framework aims to strike a balance between attracting necessary investments and preventing excessive price increases for consumers. Performance-based tariff mechanisms are also in place to incentivize DSOs to reduce losses, improve service quality, and enhance operational efficiency.

3. ***Performance Monitoring and Compliance Enforcement.*** PSRC enforces strict performance benchmarks to ensure that DSOs meet service quality standards, such as reducing power outages,

improving voltage stability, and minimizing losses. Regular audits and reporting requirements allow PSRC to track progress and intervene when necessary. Non-compliance with regulatory standards may result in penalties, performance-based adjustments, or corrective action mandates.

4. ***Facilitating Renewable Energy Integration.*** With Armenia's growing focus on renewable energy, PSRC plays a crucial role in ensuring that distribution networks can accommodate decentralized solar and wind projects. By developing regulatory guidelines for grid modernization and interconnection standards, PSRC facilitates the smooth integration of renewable sources while maintaining grid stability and reliability.
5. ***Challenges and Future Regulatory Focus.*** Despite its achievements, PSRC faces several challenges, including stakeholder resistance to tariff adjustments, the need for continuous regulatory adaptation, and ensuring that DSOs meet their investment commitments. Future regulatory priorities include strengthening grid resilience, expanding smart grid technologies, and enhancing transparency in regulatory decision-making.

By maintaining a forward-looking regulatory approach, PSRC ensures that Armenia's electricity sector remains reliable, sustainable, and competitive in an evolving energy landscape.

Objectives of the Case Study

This case study aims to:

- Analyze the technical and economic challenges posed by Armenia's ageing distribution networks.
- Assess the effectiveness of PSRC's regulatory framework in addressing these challenges.
- Compare Armenia's regulatory approach with international best practices.
- Provide strategic recommendations for enhancing regulatory oversight and network modernization.

Key Energy Sector Trends in Armenia

Rising Electricity Demand Urbanization, industrialization, and electrification of transportation have driven a steady increase in electricity consumption. Between 2010 and 2023, electricity demand grew by an average of 3.5% annually, placing additional stress on the ageing distribution infrastructure.

Renewable Energy Integration Armenia has made significant strides in diversifying its energy mix with solar, wind, and small hydropower projects. However, the intermittent nature of renewables requires a flexible and resilient distribution network. Currently, grid limitations hinder the seamless integration of renewables, necessitating urgent upgrades in grid management and storage solutions.

Smart Grid Technologies Smart grids, featuring advanced metering infrastructure (AMI), automation, and real-time monitoring, present a viable solution to Armenia's distribution challenges. Despite ongoing pilot projects, penetration remains low, particularly in rural areas. Expanding smart grid adoption can enhance demand-side management and reduce technical losses.

OVERVIEW OF THE REGULATORY LANDSCAPE: ROLE OF PSRC AND ALIGNEMENT WITH EU DIRECTIVES

The Public Services Regulatory Commission plays a central role in Armenia's energy sector by overseeing the activities of Distribution System Operators (DSOs). Its core responsibilities include tariff setting, performance monitoring, and compliance enforcement. PSRC ensures that DSOs operate in a transparent and efficient manner, aligning their investments and operations with national energy policy objectives. The Commission employs a range of regulatory tools and mechanisms, including:

- Long-term investment planning requirements
- Tariff methodologies that balance affordability and cost recovery
- Quality of Service (QoS) indicators and performance benchmarks
- Incentive and penalty schemes tied to service delivery and efficiency
- Periodic reporting, auditing, and public consultation processes

Through these instruments, PSRC maintains a regulatory environment that encourages sustainable infrastructure development while protecting consumer interests.

Armenia's regulatory landscape is increasingly shaped by its commitments under the Comprehensive and Enhanced Partnership Agreement (CEPA) with the European Union. CEPA serves as a framework for harmonizing national legislation with EU energy directives, particularly those concerning:

- Market liberalization and competition
- Renewable energy integration
- Consumer rights and protections
- Transparency and access to information
- Network access and third-party participation

PSRC has been actively revising its regulatory framework to align with EU standards, fostering a more transparent, competitive, and investor-friendly energy sector. This alignment also supports Armenia's long-term objectives for energy security, environmental sustainability, and regional cooperation.

THE PROBLEM: AGEING DISTRIBUTION NETWORKS

Causes of Ageing Infrastructure Decades of underinvestment, combined with coordination challenges and outdated grid technology, have led to high technical and commercial losses. A significant portion of Armenia's distribution network exceeds its operational lifespan, increasing maintenance costs and reliability issues. Additionally, inconsistent infrastructure upgrades have resulted in a patchwork of old and new systems, further complicating maintenance efforts and operational efficiency. The lack of a proactive asset management strategy has also contributed to the premature degradation of critical network components. Another issue were losses in the distribution system and their effect on tariff.

Impact on Consumers and the Economy

- Frequent Outages: Power interruptions have increased over the last decade, disproportionately affecting rural areas and small businesses.
- Economic Losses: Unreliable electricity supply has led to increased costs for businesses, reducing industrial productivity and discouraging investment in energy-dependent sectors.
- Social Impact: Vulnerable populations, particularly in remote regions, face limited access to stable electricity, affecting education, healthcare, and overall quality of life. Prolonged outages hinder access to digital services and modern energy-dependent appliances, widening the urban-rural development gap.

Barriers to Renewable Energy Integration

- Grid Congestion: Existing distribution networks are not designed to accommodate high levels of decentralized generation, limiting the absorption of solar and wind power.
- Weak Grid Stability: The ageing infrastructure lacks the necessary technological upgrades to handle fluctuations in renewable energy output, increasing curtailment risks and inefficiencies.

- Lack of Real-Time Monitoring: Insufficient investment in modern grid management technologies makes it difficult to balance load demand dynamically, further exacerbating integration challenges for variable renewable energy sources.

By addressing these structural weaknesses, Armenia can unlock the full potential of its renewable energy transition while ensuring long-term reliability and economic resilience.

REGULATORY SOLUTION: PSRC'S ROLE IN DSO LONG-TERM PLANNING

Requirements for Long-Term Planning Since 2015, PSRC has required DSOs to submit a detailed 10-year investment plan that includes technical and economic justifications. These plans must outline projected demand growth, necessary infrastructure upgrades, and a timeline for implementation. The goal is to ensure a structured, transparent approach to grid modernization and expansion while prioritizing cost efficiency and sustainability.

Evaluation Process PSRC assesses investment plans based on multiple criteria, including:

- Economic feasibility – Ensuring investments provide long-term financial benefits.
- Technical improvements – Addressing grid modernization needs and system reliability.
- Consumer benefits – Minimizing disruptions and optimizing service quality.
- Alignment with national energy policy – Supporting Armenia's renewable energy and market liberalization goals.

The evaluation process includes public consultations, technical audits, and independent expert reviews before final approval.

Financial Considerations and Incentive Mechanisms

To fund investments, DSOs rely on a combination of:

- Tariff adjustments – Regulated increases to ensure cost recovery.
- Loans and grants – Financing from international financial institutions and development agencies.

To promote efficiency, PSRC has implemented a system of incentives and penalties:

- Loss and costs reduction bonuses – Financial incentives for reducing technical and commercial losses and some costs. For example, the PSRC has set the distribution system losses at 7.5 percent. Currently, actual losses are around 6.5 percent, so the difference remains with the company as revenue and is not reduced from tariff calculations. The same principle applies to certain operational and maintenance costs, where actual savings below the fixed amounts benefit the company.
- Quality of Service (QoS) indicators – Although not traditional penalties, the PSRC has introduced performance-based adjustments. For example, a SAIDI (System Average Interruption Duration Index) target is established to be achieved by the end of the year. If the actual SAIDI exceeds the target, a portion of the DSO's investment, calculated proportionally to the deviation, is excluded from tariff calculations until the target is met. This mechanism incentivizes continuous service quality improvements.

These mechanisms aim to enhance accountability and encourage sustainable infrastructure development.

STRUCTURE AND IMPACT OF THE INVESTMENT PROGRAM

The charts and graphs below show the investment structure and share allocations, including:

- Funding distribution by investment category in 2016-2023

Direction	Initial Plan (USD mln)	Actual investments (USD mln)	Difference (USD mln)
Service Quality Improvement	342.82	176.15	-166.67
New Consumer Connections	71.79	170.77	98.97
Distribution Network Expansion	10.26	23.08	12.82
Commercial Metering System Improvement	147.95	187.69	39.74
Other Directions	24.62	31.79	7.18
Total	**597.44**	**589.49**	**-7.95**

Table 13. Armenian DSO, funding distribution by investment category in 2016-2023

As seen above, the investment plans for Armenia's electricity distribution sector have undergone strategic revisions in 2016-2023. Originally budgeted at **$597 million USD** (equivalent to 233 billion AMD), the **updated total investment plan** stands at approximately **$589 million USD** (229.9 billion AMD), reflecting a modest overall reduction of **$8 million USD**. This adjustment is primarily a result of reallocating resources in response to shifting priorities and emerging demand patterns.

Key Highlights

- **Service Quality Improvement**
  Funding for this area was significantly reduced from **$342.8 million USD** to **$176.1 million USD**, a decrease of **$166.7 million USD**. This reduction is not indicative of a deprioritization of quality, but rather a necessary reallocation driven by a **sharp increase in applications for new consumer connections**. The resources were redirected to address urgent expansion needs, ensuring network readiness for onboarding a growing number of new users.

- **New Consumer Connections**
  Reflecting the surge in demand, investment in this area more than doubled—from **$71.8 million USD** to **$170.8 million USD**, an increase of **$99 million USD**. This highlights the Commission's focus on enabling broader access and responding rapidly to new connection requests.

- **Distribution Network Expansion**
  Investment grew from **$10.3 million USD** to **$23.1 million USD**, ensuring infrastructure can accommodate increased loads and expanded service areas.

- **Commercial Metering System Improvement**
  Budget allocation rose from **$147.9 million USD** to **$187.7 million USD**, showing continued commitment to enhancing monitoring systems, reducing losses, and increasing operational transparency through advanced metering.

- **Other Directions**
  Smaller areas of focus received a slight increase of **$7.2 million USD**, reflecting targeted adjustments to support operational and regulatory improvements.

In conclusion, while the overall budget saw a marginal reduction, the investment rebalancing clearly demonstrates a **strategic response to growth in consumer demand**. The shift favors expanding access and modernizing grid control systems while maintaining ongoing attention to service quality through other regulatory tools.

The graph below shows breakup of investment directions by percentages:

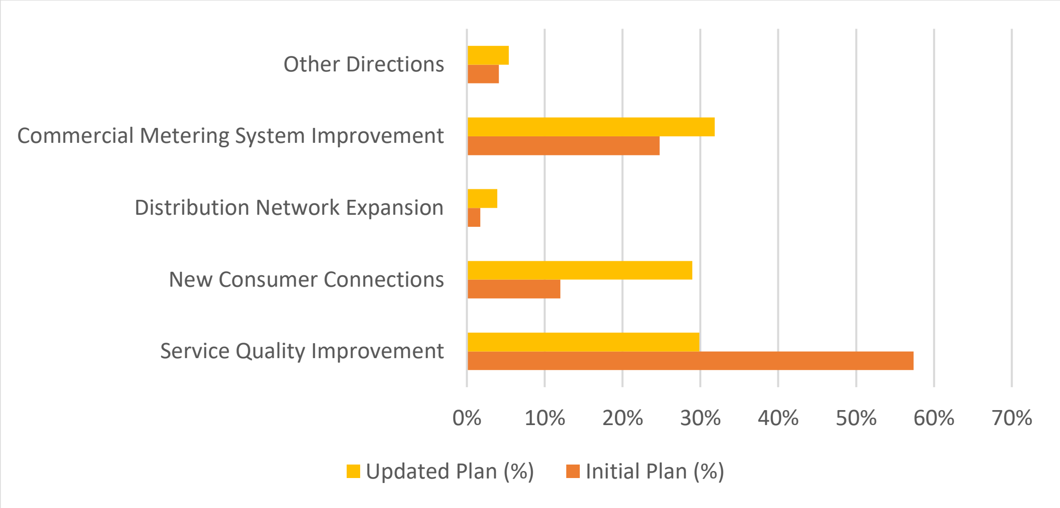

Figure 11. Armenian DSO, Investment Plan 2016-2023

RENEWAL AND EXTENSION OF THE INVESTMENT PLAN IN 2023

Although the original investment plan for Armenia's electricity distribution network was approved for the period 2016–2027, a comprehensive revision was undertaken in 2023. This revision was driven by significant differences observed between the planned and actual investments during the initial implementation years. As a result, the investment plan was not only updated to reflect more realistic financial flows and priorities, but also extended through 2034. The extension aims to provide the Distribution System Operator (DSO) with greater flexibility to reallocate financial resources in a way that more effectively addresses evolving network demands. In particular, the revised plan emphasizes targeted investments in areas that will ensure long-term improvements in service quality (QoS), system reliability, and consumer satisfaction.

The total value of 2023-2034 investment plant is around **$783 million USD**.

The graph below shows breakup of 2023-2034 investment directions by percentages:

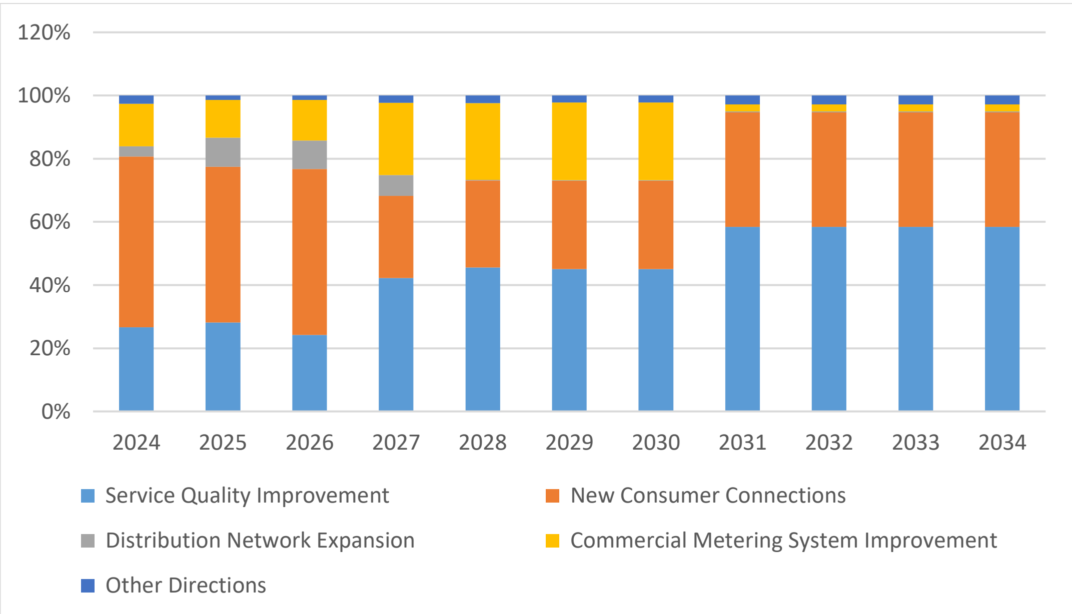

Figure 12. Armenian DSO, investment directions, 2023-2034

As illustrated in the graph, beginning in 2026, a significant shift in investment priorities becomes evident, with the majority of planned funding being allocated to improvements in service quality. This trend reflects a strategic realignment by the Distribution System Operator and the regulator to place greater emphasis on long-term network performance, reliability, and consumer satisfaction. After addressing urgent needs such as new consumer connections and system expansion in the earlier years, the investment plan transitions toward reinforcing infrastructure, reducing outages, and enhancing voltage stability. This allocation pattern demonstrates a commitment to ensuring that the distribution network can sustainably meet growing demand while delivering a consistently high level of service to end users.

Indicator	Unit of measurement	2021	2025 target	2028 target
SAIDI (Average Interruption Duration)	min/customer	886.35	664.76	487.49
	%	—	25% reduction compared to 2021	45% reduction compared to 2021
SAIFI (Average Interruption Frequency)	interruptions/ customer	8.84	6.63	4.86
	%	—	25% reduction compared to 2021	45% reduction compared to 2021
Voltage Deviation Duration	hours/ customer	1174.16	587.08	—
	%	—	50% reduction compared to 2021	100% reduction compared to 2021
Voltage Deviation Frequency	incidents/ customer	6.01	3.01	—
	%	—	50% reduction compared to 2021	100% reduction compared to 2021
Maximum Duration of a Single Outage in Urban Areas	hours	4	3	2
Maximum Duration of a Single Outage in Rural Areas	hours	8	6	4

Table 14. Armenian DSO, QoS indicators: 2021 (actual levels), 2025 and 2028 (targets)

Indicators	First phase of regulation: investment incentives					Second phase of regulation: stimulation of investments and costs reduction				Third phase of regulation: stimulation of investments and costs reduction			Fourth phase of regulation
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Technical and commercial losses	11,03%					7,50%				7.00%			6.40%
Costs	7818 mln AMD					reduction by 13.7%				Reduction by 14.7%			Reduction by 12.2 %
Staff	Staff – 7806					Staff - 6706				Staff - 6426			Staff - 6146
Bad account	1%												
Receivable	0.80%					0.70%				0.60%			0.50%
Maximum investments	250 million USD												
			120 million USD			302 million USD				218 million USD			to be defined

Table 15. Armenian DSO, Regulatory main policy objectives

Improvements in Network Performance

Targeted investments have led to measurable reductions in losses, as the graph below shows actual losses compared to the losses included in tariff calculation.

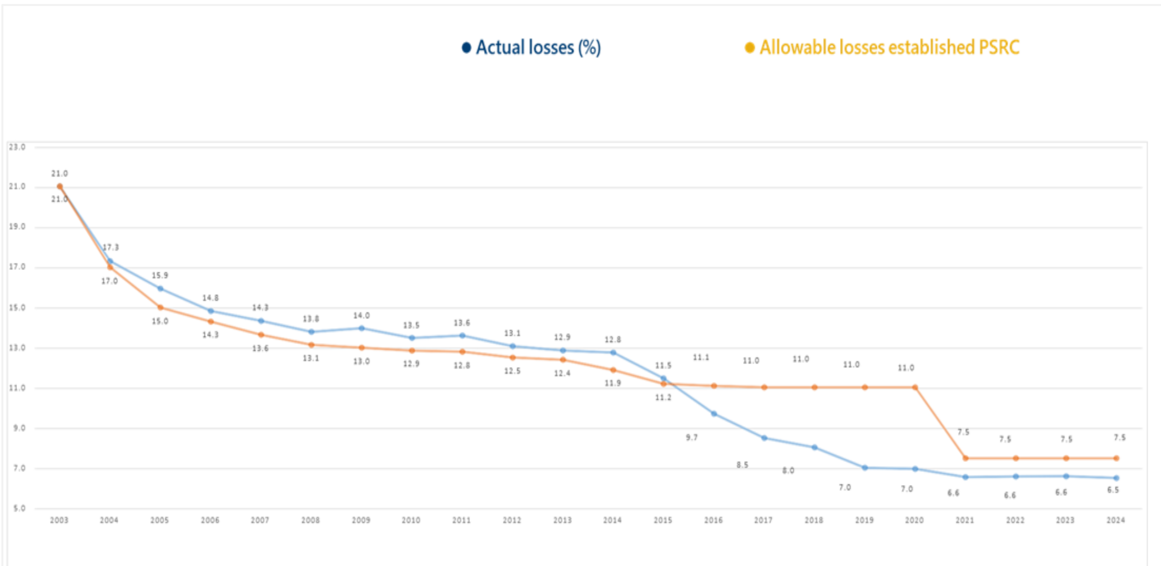

Figure 13. Armenian DSO, losses, actual vs established by the regulator (PSRC)

Conclusion

Armenia's transition to a modern electricity distribution network is vital for its economic and environmental future. The PSRC's regulatory framework has laid a strong foundation through investment mandates, tariff reform, and incentive structures. However, sustained progress requires continued focus on smart grid deployment, stakeholder engagement, and alignment with EU directives. By learning from international best practices and strengthening regulatory transparency, Armenia can build a resilient, inclusive, and future-ready energy sector.

5.2 France: Case study on Incentives for Timeliness and Efficiency of Execution of Transmission Grid Investments[13]

The projected capital expenditures of the French TSO (RTE) showcase a sharp rise, from €2,1 billion in 2023 to €6,2 billion in 2028. The substantial increase in connection requests, the need to renew and adapt the electricity transmission network to climate change, and the development of offshore wind power explains this explosion. Still, the French Regulator (CRE) regards efficiency and cost control as the necessary corollary of increased investments. Thus, it has recently taken advantage of the new generation of electricity network tariffs (TURPE 7) to adapt the regulatory incentives that will apply from the 1st of August 2025 to until at least 2029.

Incentives for TSO's investments cost-efficiency

Target budgets for major network investment projects (> €50 m)

Since 2017, the French electricity networks tariff provides a financial incentive to RTE to control the costs of its major network investment projects.

As of August 1st of 2025, it will include the new investment decisions for all types of network investments, including connections, interconnections or digital backbone projects for instance, when they exceed €50 million. CRE may also decide, for some projects or categories of projects not included in the scope, to audit the budget and apply an incentive regulation identical to that described above. Historically, this regulation included most investment decisions exceeding €30 million.

The mechanism will remain the same:

- CRE audits the budget presented by RTE, prior to undertaking any spending in works, and will set a target budget.
- Regardless of the investment expenditure incurred by RTE, if it is efficient, the asset will enter the BAR at its real value when it is commissioned (minus any subsidies);
- If the investment expenditure incurred by RTE for this project is between 95% and 105% of the target budget, no bonus or penalty will be awarded.
- if the investment expenditure incurred is less than 95% of the target budget, RTE will receive a bonus equal to 20% of the difference between 95% of the target budget and the investment expenditure incurred.
- if the investment expenditure incurred by the TSO is greater than 105% of the target budget, RTE will incur a penalty equal to 20% of the difference between the investment expenditure incurred and 105% of the target budget.

[13] Case study provided by Ivan Faucheux and Amélie Redortier, Commissione de Regulation de l'Energie (CRE), France

Minimizing the unit costs of recurring network investments

Under TURPE 7, CRE has removed its four-year investment ceiling for the French TSO but has introduced incentive regulation to control the unit costs of asset management and recurring investments in the network. It ought to promote asset management operations with the most favorable cost conditions, without bias between operating costs and investment expenditure.

The mechanism provides for an incentive on 20% of the differences between the reference unit costs and the costs incurred over the entire incentivized scope. CRE has defined a public list of operations covered by this regulation.[14] Its scope covers €166 million/year in operating costs and €450 million/year in investment expenditure.

INCENTIVES FOR TSO'S TIME-EFFICIENCY

Target milestones for high-priority projects

With TURPE 7, CRE introduced a new incentive regulation in the network tariff to ensure that high-priority projects are completed on time. In the course of 2025, CRE will draw up a list of projects and associated milestones (submission of the technical and economic justification for the project, start of work, commissioning, for example) based on the TSO's 10-year network development plan.

As of the 1st of August 2025, the TSO will receive a bonus of €500,000 for each milestone reached within the specified time frame. Failure to reach the selected milestones within the allotted time will result in the payment of a penalty by RTE. Calculated monthly, the amount of this penalty increases progressively in order to penalize significant delays more heavily:

- up to the 6th month of delay, a penalty of €100k/month of delay is applied;
- from the 6th month of delay up to the 12th month of delay, the penalty is €200k/month of delay;
- beyond the 12th month of delay, the penalty is €400k/month of delay.

The total amount of penalties and bonuses applied under this incentive is capped at +/-€10 million per year.

A lower compensation for assets under construction

To prompt system operators to quickly commission their investment projects, the French electricity network tariffs compensate assets under construction (AUC) at the nominal cost of debt, which is lower than the weighted average cost of capital (WACC).

In the context of TURPE 7, CRE has, however, introduced an exception for assets used to connect offshore wind farms. From August 1, 2025, these specific AUC will be compensated using the WACC (without the specific premium for assets commissioned).

This differentiation is explained by the significantly longer current downtime of offshore wind farm connection projects, in particular due to any associated advance payments. In any case, CRE has maintained an incentive scheme specific to compensation paid to producers in the event of a delay in construction or damage on the connection lines, whose costs might not be included in the recovered costs depending on an efficiency analysis.

[14] Regarding investment specifically : synchronized rebuilding of supports and conductors in place of overhead lines at voltage levels HVB 1 and HVB 2; o renewal of control systems in substations at voltage levels HVB 1, HVB 2 and HVB 3; o certain substation component replacement operations (circuit breakers, disconnectors, instrument transformers) and mid-life rehabilitation of power transformers.

5.3 GEORGIA: CASE STUDY ON INVESTMENT APPRAISAL RULES AND PROCEDURES[15]

The rules and procedures for evaluating investments in the electricity sector in Georgia have been approved by the Georgian National Energy and Water Supply Regulatory Commission (GNERC) in accordance with legislative requirements and international best practices.

The purpose of the Rule for the Appraisal of Investments in the Electricity Sector is to define the main principles and criteria for the development, submission, appraisal, approval, monitoring, and amendment of investment plans of enterprises subject to tariff regulation and their constituent investment projects. The investment plan agreed upon in accordance with the "Rule for the Appraisal of Investments in the Electricity Sector" shall be reflected in the tariff calculation in compliance with the principles defined by the tariff methodology.

GNERC appraises the expediency and reasonableness of the submitted investment projects, taking into account the criteria of necessity and efficiency. For an investment project to be considered necessary, the relevant enterprise must substantiate its necessity for the safe, reliable, and efficient operation of energy systems. For an investment project to be considered efficient, the relevant enterprise must substantiate that the investment project is planned based on the principle of cost reasonableness and that its quantitative benefit exceeds the total cost of the project to be considered in the tariffs.

Investment projects are classified into the following categories:

- ***Category I. Investment projects related to network reliability/stability and efficient operation*** – network rehabilitation, reconstruction, modernization, and/or replacement of existing, damaged, or obsolete assets;
- ***Category II. Investment projects related to security of supply and diversification*** – investments made for the purposes of security of supply and diversification, for electricity generation, as well as in the construction of new infrastructure of the electricity transmission and distribution network;
- ***Category III. Investment projects related to system development and expansion*** – investments made in the construction of new infrastructure of the electricity transmission and distribution network for electricity generation in response to increased/forecasted demand;
- ***Category IV. Other types of investment projects*** – projects related to environmental protection, renewable energy integration, and/or energy efficiency improvement;
- ***Category V. Non-network investment projects*** – investment projects that do not fall under network investment projects classified in Categories I-IV, such as investments in intangible assets, office equipment, vehicles, administrative buildings and structures, communication devices, computer equipment, and various special devices.

The enterprise shall develop an investment plan and submit it to the GNERC for approval. The investment plan shall be developed in a manner that ensures the enterprise's activities are carried out with maximum efficiency, considering the requirements of applicable legislation.

The enterprise shall submit the investment plan to the GNERC in the tariff calculation year, no later than June 1. In addition to this, the transmission system operator shall submit the Ten-Year Transmission Network Development Plan and the distribution system operator - Five-Year Distribution Network Development Plan to the GNERC annually.

[15] Case study provided by Ms Lica Gavzava, Georgian National Energy Regulatory Commission (GNERC)

GNERC reviews investment plans submitted by enterprises in the tariff calculation year within 90 calendar days from the date of receipt. Within this period, the Commission shall:

- Approve the submitted investment plan, or
- Notify the relevant enterprise in writing of any comments or additional documentation requirements if the investment plan is not submitted in the form specified by the Commission, is incomplete, or requires additional documentation and justification. Additionally, the enterprise may be required to submit technical and economic indicators for alternative scenarios of the investment project's development.

GNERC shall grant the enterprise an additional period of no more than 45 calendar days. After the enterprise submits the information/documentation within the time-frame GNERC shall review the revised investment plan and decide on its approval, partial approval, or rejection.

The investment plan submitted to the Commission in the tariff calculation year shall include the following information (format is approved by GNERC):

- Unified information on all planned investment projects
- For each network investment project, a forecast cost estimate
- For each network investment project to be implemented in the first year of the investment plan, project documentation, except for aggregated investment projects in Category I
- For non-network investment projects, a forecast cost estimate
- Information on related investment projects (current status and implementation schedule)
- For each Category I investment project, accident statistics, defect reports, measurement protocols, and/or information on repairs carried out.

In addition to the above-mentioned, GNERC is authorized to request additional information from the enterprise regarding the investment project. GNERC also is authorized to require the enterprise to submit alternative scenario(s) for the implementation of the investment project.

If the annual change in the value of the agreed investment plan is at least 10%, the enterprise is obliged to apply to the Commission with a request for amendments to the investment plan.

Investment project(s) implemented without prior approval may be fully considered in the base of regulated assets only if the investment project(s) was carried out to restore an asset destroyed or damaged due to force majeure, and at the same time, within 15 days of the resolution of the incident, the enterprise has notified the Commission in writing about the destruction or damage of the specific property as a result of force majeure.

The technical feasibility criteria for an investment project include:

- For operators of electricity transmission and distribution systems:
  - Indicators of electricity supply interruptions;
  - Indicator of undelivered electricity volume;
  - Indicator of electricity losses;
  - Electricity quality indicator, including for distribution system operators, in the case of damage to one power element (transformer, circuit breaker, and/or other) in a 35-110 kV two-transformer distribution substation, the indicator of the percentage reduction in load loss connected to the substation;
  - Integration of renewable energy sources into the distribution network.

- For electricity producers:
  - Indicator of undelivered electricity volume;
  - Accident statistics;
  - Indicator of the volume of spilled water, if it was not caused by an instruction from the dispatcher of the transmission system operator.

For the purpose of approving investment projects, the Commission shall:

- Verify the technical feasibility criteria. In order to be included in the investment plan, the implementation of the investment project(s) must improve at least one technical feasibility criterion;
- Examine the results of the financial analysis.
- Examine the results of the economic analysis.
- Evaluate the forecast costs of an individual investment project, The Commission shall assess the reasonableness and efficiency of costs using comparative analysis (benchmarking), normative cost per unit as set out in construction norms and standards, market prices, and expert conclusions;
- Verify the necessary permits (e.g., construction permits, administrative approvals) for investment projects to be implemented in the first year of the tariff regulation period, if applicable;
- Assess the availability and reasonableness of financial resources required for the implementation of the investment project. The enterprise must substantiate that the available and/or raised financial resources align with the financial needs of the project. GNERC shall not approve an investment project if the enterprise fails to justify the availability and/or reasonableness of the necessary financial resources;
- Evaluate the individual and cumulative impact of investment projects on the enterprise's tariff.
- Evaluate the alternative scenario(s) for the implementation of the investment project as prepared by the enterprise.

Non-network investment projects included in the investment plan shall be appraised individually, based on the forecast cost information taking into account the principles of cost-effectiveness and reasonableness.

By June 1 of each year, the enterprise shall submit to the Commission a report on the actual implementation of the investment plan for the previous year. The enterprise shall submit information to the Commission on the implementation of investment projects exceeding GEL 5 million within 30 calendar days after the completion of the entire investment project and the commissioning of the relevant property/infrastructure.

The enterprise is obliged to submit the following information to the Commission regarding the actual implementation of investment projects:

- A list of works performed and actual expenses incurred under the investment project:
  - For network investment projects (format is approved by GNERC);
  - For non-network investment projects (format is approved by GNERC);
- The act of acceptance and transfer of completed works, documentation on performed works and installed equipment, and/or commissioning certificate;
- Photographic evidence of the implemented investment project.

The enterprise shall compare the planned and actual costs and works (including implementation timelines) of each investment project. In the event of discrepancies, the enterprise shall provide a justification for such differences in the report on the actual implementation of the investment plan.

GNERC reviews the report submitted by the enterprise on the actual implementation of the investment plan for the previous tariff regulation period and shall decide whether to consider or disregard the difference between actual and planned investments in the tariff of the next tariff regulation period.

5.4 North Macedonia: Case Study on Tariff Inclusion of Approved Investments[16]

In accordance with the Energy Law, the North Macedonian regulator (ERC) adopts decisions for tariffs for usage of the transmission and distribution network. Furthermore, for each regulated period, the electricity transmission system operator shall prepare and submit for approval to the ERC investment plans in the electricity transmission system, in which, because of the investments foreseen, the following should be shown:

1. the expected increase in the efficiency of the operation of the electricity transmission system by reducing the losses of electricity,
2. improvement of the quality of the delivered electricity from the electricity transmission network and,
3. the impact on the increasement of the number of power plants that use renewable energy sources and their spatial distribution.

The same obligation is for the distribution system operator as well. ERC also approves investment plans of the Distribution system operator.

For each year of the regulated period, that is 3 years for electricity transmission and electricity distribution, ERC sets basic revenue, which is composed of operational costs, deprecation and return on assets.

Basic revenue is not adjusted for the regulated period and is set before the beginning of the regulated period. It means that also approved investments are not adjusted.

One of the parts of the return of assets that should be calculated is regulated assets base (RAB). In the calculation of RAB, new investment should be taken into consideration for the three years regulated period and they are defined as „Approved investments, in line with the approved investment plan in the respective system, by the ERC, which shall particularly present the expected increase of the efficiency of system operation by reducing electricity losses and by improving the quality of the delivered electricity, due to predicted investments, that comprise investments financed through grants and connection assets transferred to the ownership of the operator of the respective grid".

To set the value of the new investments ERC checks the actual investments of the TSO and DSO in the previous years and compares it with the approved new investments in the previous regulated period. Usually, investments are divided into categories such as equipment, construction facilities, transportation vehicles, office equipment, office furniture, non-material assets, free received assets, etc in general. ERC checks if the actual investments in every category have been previously approved and the percentage of realization. This is done for every category of investments. Finally, we calculate the final percentage of the actual cost.

If the actual investments are on the level of approved once with appropriate justification, then we take into account the level of new investments for the next regulated period that corresponds to the actual investments in the previous period and additionally we take into account investments that are necessary and justified for the next period.

[16] Case study provided by Elena Kolevska, Energy, Water Services and Municipal Waste Management Services Regulatory Commission (ERC) of North Macedonia

If actual investments are well below the approved once by ERC in the previous regulated period, then ERC does not take all proposed new investments by the operators but those that correspond on the level of actual in the previous regulated period.

This approach gives signal to the operators that they should invest in the justified projects in the networks at least on the level of approved by the regulator so they should have incentive for the next regulated period. At the end, rate of return on the envisaged assets is included in the tariffs and paid by system users.

With this approach, the network operators are incentivized by ad hoc approved investments in the RAB, penalized with decreased level of approved investments in the next regulatory period, if not investing according to the plan/approved investments, the investments are included in the tariffs and the operators in general have accepted this approach as fair.

5.5 Rhode Island (US): Case Study on Investment Approval, Cost Recovery and Monitoring

Rhode Island's Infrastructure, Safety, and Reliability Investment Mechanism[17]

The Rhode Island Public Utilities Commission (hereafter "Commission") is the State regulatory authority responsible for overseeing electric and gas utilities in Rhode Island (U.S.). The Division of Public Utilities and Carriers (hereafter "Division") serves as the final customer ("ratepayer") advocate in regulatory proceedings.

In the years leading up to the establishment of the Infrastructure, Safety, and Reliability (ISR) mechanism, Rhode Island's electric and gas utility landscape was shaped by corporate mergers, rate freezes, and debates over regulatory mechanisms to support infrastructure investment. In the U.S. regulatory system, utilities typically recover their costs and earn returns through "rate cases" - formal regulatory proceedings where allowed tariffs ("rates") are set based on the utility's costs and allowed return on investment.

The merger of three electric companies in 2000 led to a decrease in authorized revenue and a five-year rate freeze (a period during which utility rates cannot be increased).[18] When National Grid acquired these companies in 2005, it accepted another revenue reduction and a further five-year rate freeze.[19] In 2009, following the expiration of these freezes, the Narragansett Electric Company[20] presented to the Commission a proposal for new electricity tariffs ("rate case") and requested a capital tracker mechanism to recover the cost of incremental investments made between rate cases – so addressing "regulatory lag", the delay between when a utility makes an investment and when it begins earning a return on that investment through tariffs.[21]

This request followed a similar case for the gas utility. In 2008, the Commission approved a reconciling mechanism for the gas utility – known as the Accelerated Replacement Program (ARP) – based on evidence of need. The utility cited a sustained and rising number of gas leaks in the state's aging gas distribution system,

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[17] Case study provided by Ms Abigail Anthony, Commissioner of the Public Utility Commission of Rhode Island (US)

[18] Order No. 16200 (issued March 24, 2000); Third Amended Stipulation & Settlement.

[19] Docket 3617, Order No. 18037, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/3617-NECOrd18037%2811.9.04%29.pdf.

[20] The Narragansett Electric Company d/b/a National Grid was the primary distribution utility serving Rhode Island electric and gas customers until PPL Corporation completed its acquisition of the Narragansett Electric Company on May 25, 2022. Following the acquisition, The Narragansett Electric Company began doing business as Rhode Island Energy. This marked the formal transition of ownership and operational control of electric and gas distribution services in Rhode Island from National Grid to PPL Corporation.

[21] RI PUC Docket 4065, Direct testimony of Tom King, pg. 5, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4065-NGrid-DirectVol1%286-1-09%29.pdf

prompting the utility to propose an accelerated plan to remove bare steel mains and services, and cast-iron mains. The ratepayer advocate, the Division of Public Utilities and Carriers (Division), supported the ARP, and the Commission found that the evidence demonstrated a clear need for accelerated investment. The ARP was approved with a reconciling recovery mechanism to fund the incremental costs above routine pipeline replacement levels, balancing safety benefits with ratepayer impacts.[22]

In contrast, when National Grid proposed a capital tracker for its electric distribution system, the Commission rejected the request. The utility argued that traditional cost-of-service regulation did not support needed investment since capital expenditure made after a rate case did not generate returns until a subsequent rate case. The utility sought to reduce such a regulatory lag by recovering the incremental revenue requirement associated with capital investment made between rate cases through a capital tracker, cautioning that deferring investment would only magnify future reliability and safety issues. However, the Commission found that the utility had not demonstrated the same clear evidence of need as in the gas case. Specifically, National Grid's electric system had maintained high reliability with lower spending levels, and the utility's investment levels were consistent with industry peers. The Commission concluded that the proposed capital tracker would circumvent traditional ratemaking safeguards and diminish regulatory oversight.[23]

ESTABLISHMENT OF THE ISR MECHANISM

After the Commission denied its capital tracker proposal, the utility turned to state lawmakers and successfully sought legislative authorization for a similar mechanism through state law.[24] The ISR law created an annual framework, allowing electric and gas utilities to propose and recover costs associated with infrastructure, safety, and reliability investments between rate cases.

Under this law, the utility presents an annual ISR plan to the Commission outlining planned investments and associated operations and maintenance (O&M) expenses. The Commission reviews these plans to ensure that they are reasonably needed to maintain safe and reliable distribution service in both the short and long term. The costs of approved investments are added to the rate base once placed in service, while O&M expenses are recovered annually.[25] The law allows the utility to forecast the expected plant-in-service for the upcoming 12-month period and begin recovering the revenue requirement associated with those in-service projections immediately, eliminating regulatory lag.

SCOPE AND COMPONENTS OF ELECTRIC AND NATURAL GAS ISR PLANS

The electric and gas ISR plans address aging, obsolete, inadequate, or damaged infrastructure, and accommodate public works. The gas ISR plan also addresses gas system expansion projects. The electric ISR plan may include system performance and capacity upgrades to address load constraints caused by growing or shifting customer demands on the system. The electric ISR includes O&M expenses for vegetation management, inspection and maintenance, and volt-var optimization and conservation voltage reduction; the gas ISR includes O&M expense for road paving.

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[22] RI PUC Docket 3943, Order No. 19563, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/3943-NGrid-Ord19563%281-29-09%29.pdf.

[23] RI PUC Docket 4065, Order No. 19965A, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4065-NGrid-Ord19965A%284-29-10%29.pdf

[24] R.I.General Laws § 39-1-27.7.1: https://webserver.rilegislature.gov/Statutes/TITLE39/39-1/39-1-27.7.1.HTM.

[25] RIPUC No. 2255, Infrastructure, Safety, and Reliability Provision, https://www.rienergy.com/site/-/media/rie-jss-app/home/ways-to-save/rates-and-shopping/service-rates/residential-rates/tariff-provisions/tariff-provisions/5bisrprovripuc2255090122.ashx.

ISR REVIEW PROCESS

The ISR process operates on an annual cycle, with the plan year running from April 1 through March 31. By December 31 of each year, the utility submits its proposed ISR plan to the Commission. Prior to filing, the utility works with the ratepayer advocate to review and refine the plan through discovery and negotiation, a process that can lead to substantial revisions. Once filed, the Commission has 90 days to seek public input and conduct a formal review involving discovery, expert witness testimony from the utility, ratepayer advocate, and intervening parties, and hearings.[26]

The Commission's review is focused on the central statutory standard of necessity for safety and reliability, and maintains a skeptical stance on pre-approving discretionary spending. While the utility often puts forward investment proposals that may offer operational benefits, the Commission's review serves to determine whether those investments are needed now. The Commission is acutely aware that the ISR mechanism, by enabling pre-approval and timely cost recovery, shifts the investment risk from the utility to the Commission and ratepayers.[27] Consequently, the Commission seeks to apply this exception to normal ratemaking judiciously and maintain a careful balance between regulatory flexibility and ratepayer protection.

Commission decisions in recent years illustrate this approach. The Commission has rejected electric ISR proposals for grid modernization investments such as advanced capacitors, reclosers, and visibility equipment, finding that the utility did not provide evidence of a near-term need based on system conditions, reliability trends, or compliance with public policy.[28] While the utility proposed new investment programs in reclosers on the basis of declining reliability, the utility's SAIFI and SAIDI performance (international reliability metrics measuring frequency and duration of interruptions) consistently met regulatory benchmarks, and no data supported a deterioration in service quality.[29] Most recently, the Commission declined to increase the utility's ISR budget for discretionary system capacity and performance investments when the utility was observed to be pursuing reliability performance goals that exceed regulatory requirements, prompting the Commission to question whether the utility was appropriately prioritizing truly needed investments over discretionary enhancements.[30]

The Commission applies the same approach to the review of ISR proposals from the natural gas utility. The focus on understanding whether proposed investments are demonstrably needed for safety and reliability in the near and long term takes on additional significance in light of Rhode Island's Act on Climate,[31] which mandates economy-wide net-zero greenhouse gas emissions by 2050. The Act on Climate raises the potential of decommissioning the natural gas distribution network, and with it, the risk of stranded costs from unneeded and undepreciated infrastructure.[32] Traditionally, the gas utility's ISR plans have centered on a mileage-based strategy to replace leak prone pipe by 2035, incorporating a mix of low-, medium-, and high-risk segments for replacement each year. Recently, the Commission signaled the need for an outcome-based approach. In recent

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[26] R.I.General Laws § 39-1-27.7.1: https://webserver.rilegislature.gov/Statutes/TITLE39/39-1/39-1-27.7.1.HTM.

[27] RI PUC Docket 22-53-EL, Order 24873, pg. 15-16. Available here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-12/2253-RIE-Ord24873-FY2024_12-1-23.pdf

[28] Id. 18

[29] RI PUC Docket 23-48-EL, Order 25178, pg. 14-21. Available here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-10/RI%20Energy%202348-EL%20FY2025%20Electric%20ISR%20Order%2010-25-24.pdf

[30] RI PUC Docket 24-54-EL, Testimony of Gregory L. Booth, P.E., pg. 5. Available here; https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2025-02/24-54-EL%20FY26%20ISR%20-%20DPUC%20Direct%20Testimony%20of%20GLB%20%282-20-25%29.pdf

[31] R.I.General Laws §42-6.2: https://webserver.rilegislature.gov/Statutes/TITLE42/42-6.2/INDEX.htm

[32] RI PUC Docket 22-54-NG, Order 24802, pg. 33. Available here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-08/2254-RIEnergy-GasISR-FY2024-Ord24802_8-22-23_0.pdf

decisions, the Commission found that postponing the replacement of low-risk main does not compromise a near-term need and accordingly reduced the utility's proposed leak prone pipe replacement budget. At the same time, the Commission has supported pre-approval of investment in replacing medium- and high-risk segments, affirming that ISR treatment should be reserved for investments clearly needed to ensure safe and reliable operation of the gas system.[33]

COST RECOVERY AND RECONCILIATION

Cost recovery under the ISR mechanism is structured and reconciled annually. Effective April 1 each year, the Commission approves a capital expenditure factor reflecting the revenue requirement for actual incremental investments made since the last general rate case, and the revenue requirement associated with the forecasted investment approved by the Commission for the upcoming 12- month period.[34] Historically, investments were categorized as discretionary and non-discretionary, with discretionary recovery limited to the lower of actual investment or the approved budget. The capital expenditure factor is recovered through the distribution charge on customer bills. This approach can encourage on-time and on-budget investments because the amount eligible for preferential cost recovery is limited to the budgeted amount, and any over-budget costs face regulatory lag.

The Commission also approves an O&M expense factor each April 1, which is similarly recovered through distribution charges.

By August 1, the utility files proposes reconciliation factors to refund or recover the differences between billings and the lesser of actual plant in service or approved discretionary spending (or actual non-discretionary spending).[35] If circumstances encountered during the execution of the annual ISR plan required the utility to deviate from its planned capital additions by more than 10 percent, the utility must provide evidence that the spending was reasonable and prudent.

Once new base rates are implemented in a general rate case, all ISR capital additions are rolled into the utility's rate base and the capital expenditure factor resets to zero. The electric and gas utility's last general rate case was in 2018.[36]

RECENT REFORMS TO THE ISR BUDGET FRAMEWORK

In recent years, the Commission has expressed concern about rising ISR budgets, resulting increased revenue requirements, and the long-term impact on rates. In the utility's FY2025 electric ISR plan, for example, the company forecasted a nearly 70 percent increase in capital spending from FY 2024 to FY 2027.[37] In the fiscal year 2025 ISR plan, a new budgeting framework was adopted by the Commission to better control spending and better balance the sharing of risk between the utility and ratepayers. There were three key changes. First, a single capital budget now replaces separate discretionary and non-discretionary categories. If actual

[33] Id. Pg. 34-35.

[34] Typically, in the first year when plant goes into service, the Commission has used a "half-year" convention for the revenue requirement.

[35] RIPUC No. 2255; The Narragansett Electric Company's Infrastructure, Safety, and Reliability Provision, Sheet 2. Available here: https://www.rienergy.com/site/-/media/rie-jss-app/home/ways-to-save/rates-and-shopping/service-rates/residential-rates/tariff-provisions/tariff-provisions/5bisrprovripuc2255090122.ashx

[36] https://ripuc.ri.gov/eventsactions/docket/4770page.html.

[37] RIPUC Docket 23-48-EL; The Narragansett Electric Company's FY 2025 Electric Infrastructure, Safety, and Reliability (ISR) Plan, Book 1, PDF pg. 110 or Bates pg. 86. Available here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-01/2348-RIE-Book1-ElecISRPlan_12-21-23.pdf

spending exceeds the approved budget by more than 2.5%, a one-year revenue requirement adjustment applies to the excess.[38]

The intended effect of this change is to motivate the utility to balance discretionary and non-discretionary projects. Second, major projects (budgets in excess of $5 million) are subject to individual budget caps, with similar 2.5% buffers. Third, O&M expenses are grouped into separate budgets (e.g. vegetation management, I&M, VVO/CVR), each with a 10% overspend threshold. O&M costs above this level are disallowed. The revised framework aims to promote fiscal discipline while preserving flexibility to respond to emerging reliability or safety concerns.[39]

CONCLUSIONS

While it is common in the northeastern United States for utilities to have access to capital trackers that reduce regulatory lag to varying degrees, it is my impression – based on general knowledge and experience, but not research – that Rhode Island's ISR mechanism is relatively unique in allowing utilities to begin recovering the revenue requirement associated with forecasted plant in service. This feature effectively eliminates regulatory lag for planned capital additions approved by the Commission, shifting both investment risk and decision-making responsibility in ways that demand a high level of scrutiny. In my opinion, allowing this forward-looking recovery necessitates a disciplined regulatory philosophy of requiring clear evidence that the investments are needed for safety and reliability in the near and long term, and underscores the importance of maintaining balance between timely infrastructure investment and ratepayer protection in an evolving energy landscape.

[38] To illustrate how this works, consider two scenarios – without and with overspending. In both cases, the utility's accurately forecasts $90 million of plant in service at the end of the ISR year, so the long-term rate base is the same. (For the purpose of this example, assume that the revenue requirement on $90 million in capital is $3 million per year). However, the spending required to achieve that outcome differs: the utility stays within its approved $100 million budget in the first case but spends $120 million in the overspending case. In the first year, the revenue requirement is unaffected because it is based only on the half-year revenue requirement of forecast plant placed in service, meaning the utility is allowed to recover $1.5 million in year one. The difference becomes visible in the second year, when the Commission reconciles spending. Under the new budget framework, if the utility overspends its approved budget by more than the allowed buffer, recovery of the revenue requirement associated with that excess is delayed by one year. In this example, the utility overspent by $20 million, so the corresponding revenue requirement – or $667,000- is deferred. As a result, instead of recovering the full $3 million in year 2, the utility recovers only $2.3 million, with the remaining $667,000 deferred and recovered in the third year. The provision of the budget framework is available in RIPUC Docket 23-48-EL, Order 25178, page 24. Available here: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-10/RI%20Energy%202348-EL%20FY2025%20Electric%20ISR%20Order%2010-25-24.pdf

[39] RIPUC Docket 23-48-EL, Order No. 25178, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-10/RI%20Energy%202348-EL%20FY2025%20Electric%20ISR%20Order%2010-25-24.pdf.

6. Conclusions and Recommendations

6.1 The gridlock scenario

There is a growing concern that in the next years grid investments could become a critical issue for the energy transition. With the Report "Navigating Power Grid in the Age of Renewable Energy",[40] ERRA signalled that grid congestion is already a problem in most of select ERRA countries, for all or some zones. Therefore, all options to ease grid scarcity, from quick fixes to more fundamental solutions – are to be explored. Among these, the Grid Enhancing Technologies (GETs) are still not widespread but can really create new "virtual" capacity and mitigate or postponing the need for development.[41] Optimising the use of existing grid infrastructure through digital technologies provides also "a safety valve for networks and supply chains"[42] that are under strain for the pressure on new infrastructure investments.

The issues related to grid planning are of paramount relevance, as shown also by the Action Grid Plan issued the European Commission[43], that puts the enhancement of the long-term grid planning, both at transmission and distribution level, among the seven more important challenges to be tackled. In this context, grid operators require regulators to design mechanism that allow for "anticipatory investments", i.e. investments that proactively addresses expected developments, looking beyond immediate needs of generation or demand, assuming with sufficient level of certainty that new generation and demand will materialise, notwithstanding potential low utilisation in the short term.[44]

According Eurelectric, "anticipatory investments" should be based on the Network development plans (NDPs) prepared by DSOs according to the European legislation: "*DSOs' NDPs should become the primary mechanism for projecting anticipatory investment. A fast-tracked and streamlined process must provide adequate incentives for DSOs to make anticipatory investments in a stable and predictable investment environment*". On other side, NDPs should have a longer horizon than now, reaching 10 to 15 years.

In the European Union, the Agency for cooperation of energy regulators took a position on anticipatory investments[45], after having conducted a survey on national regulatory authorities and stated that so far "several NRAs respondents mentioned that no particular issues with anticipatory investments arise at national level and consequently no further actions are needed", but at the same time recommending future network users to flag their potential connection request as early as possible, as well as an early exchange of information among

[40] Patò Z., Claeys B. & Morawiecka M. (2024, October), Navigating Power Grid in the Age of Renewable Energy. Policy and Regulatory Context and Tool. Regulatory Assistance Project, Energy Regulators Regional Association, https://erranet.org/download/erra-rap-2024-grid-paper/?wpdmdl=133745&refresh=67c077a098f3e1740666784

[41] IEA, "Electricity Grids and Secure Energy Transitions, 2023 https://www.iea.org/reports/electricity-grids-and-secure-energy-transitions

[42] IEA, Building the Future Transmission Grid. Strategies to Navigate Suply Chain Challenges, 2025 https://www.iea.org/reports/building-the-future-transmission-grid

[43] European Commission, Grids, the missing link - An EU Action Plan for Grids, 28 Nov. 2023, COM(2023) 757 final https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52023DC0757

[44] Eurelectric, Grid for Speed, 2024 https://powersummit2024.eurelectric.org/wp-content/uploads/2024/07/Grids-for-Speed_Report_FINAL_Clean.pdf

[45] ACER,European Agency for Cooperation of Energy Regulators, Position on Anticipatory Investments, March 2024 https://www.acer.europa.eu/sites/default/files/documents/Position%20Papers/ACER-CEER_Paper_anticipatory_investments.pdf

future network users (including EV recharge operators) and network operators. The debate on "anticipatory investments" as a solution to the "gridlock problem" is very open.[46,47]

The survey summarised in this report shows how important are both the regulatory assessment stage of the grid plans prepared by the grid operators as well as the execution and monitoring stage; it also suggests that further steps could be taken to strengthen the regulatory action in both stages.

In the next paragraph, a list of recommendations for regulatory actions is provided as a first output of the present survey. Further work will be developed in future by ERRA to build a regulatory "toolbox" useful to regulators to avoid the risk of gridlock.

6.2 Main Findings and Key Takeaways

The context

- Electricity grids face simultaneous challenges of renewable integration, growing demand, and reliability requirements across both transmission and distribution levels.
- Smart grid technologies offer solutions for optimizing existing infrastructure while enabling demand-side management and renewable integration.
- Regulatory frameworks must balance enabling necessary investments with protecting consumers from unnecessary costs.
- Cost-benefit analysis frameworks are evolving to capture broader economic, environmental, and social benefits beyond traditional metrics.
- Effective stakeholder engagement throughout the planning process is increasingly recognized as essential for successful grid development.

The Regulatory Framework for Grid Planning Evaluation

- Modern grid planning must address both conventional infrastructure needs and emerging technological solutions through robust yet flexible assessment frameworks.
- Project categorization (reliability/resilience, expansion, competition/market functioning) can provide a structured approach to evaluating infrastructure against appropriate criteria.
- Risk assessment must now consider climate change impacts, cybersecurity threats, and technology evolution alongside traditional technical and financial risks.
- Regional coordination is essential for cross-border projects, requiring sophisticated frameworks for cost allocation and benefit sharing.
- Regulatory oversight must balance providing certainty for project developers with maintaining flexibility to adapt to changing circumstances.

[46] ENTSO-e Position paper, Anticipatory Investments, 2024, https://www.entsoe.eu/2024/12/09/entso-e-position-on-anticipatory-investments/

[47] Eurelectric Position paper, How can DSOs rise to the investments challenge? Implementing Anticipatory Investments for an efficient distribution grid, 2024 https://eurelectric.org/wp-content/uploads/2024/06/how-can-dsos-rise-to-the-investments-challenge-implementing-anticipatory-investments.pdf

KEY TAKEAWAYS OF THE ERRA SURVEY ON GRID PLAN REGULATORY ASSESSMENT

- Most jurisdictions have established well-structured, legally-based processes for evaluating grid investments, with requirements predominantly set by regulators.
- Core content requirements (infrastructure descriptions, costs, timelines) are consistent across jurisdictions, while more advanced elements (RES integration, environmental impacts) vary significantly.
- CBA implementation varies widely, from comprehensive frameworks to ad hoc analyses, with substantial differences in thresholds.
- Multiple scenario planning and uncertainty analysis remain underdeveloped, with most countries focusing on short to medium-term horizons (3-10 years).
- Stakeholder consultation is common practice, though duration requirements vary from 30 days to 6 months, with limited stakeholder participation frequently reported as a challenge.

KEY TAKEAWAYS OF THE ERRA SURVEY ON INCENTIVES FOR INVESTMENT EXECUTION

- Financial viability assessment is required by most regulators, though approaches to tariff recognition range from at-approval to at-commissioning.
- Advanced incentive frameworks for timeliness and efficiency remain limited, with notable examples including Oman's PDI scheme (see paragraph 4.2) and France's example (see paragraph 5.2).
- Countries with more developed regulatory systems tend to have more comprehensive monitoring processes with regular reporting requirements.
- The balance between regulatory oversight and operator flexibility remains a key challenge in investment monitoring frameworks.

6.3 FINAL RECOMMENDATIONS

The survey results and case studies presented in this report reveal both significant progress and substantial opportunities for improvement in regulatory frameworks for grid investment evaluation and execution. As power systems worldwide face unprecedented challenges from the energy transition, several key recommendations emerge from our analysis that can help regulators address the growing risk of grid congestion while ensuring consumer protection and economic efficiency.

1. First and foremost, **grid congestion is increasingly recognized as a critical constraint for the energy transition**, with most countries reporting congestion issues in all or some zones of their systems (as in previous ERRA surveys). **This growing challenge requires enhanced planning frameworks at both transmission and distribution levels**. The experience of jurisdictions with more advanced regulatory systems suggests that formal assessment processes with clear legal foundations and structured templates provide a strong foundation for effective grid development. Regulators should consider **establishing or strengthening structured evaluation processes that include standardized information requirements, formal consultation procedures, and transparent approval mechanisms**. These frameworks should be legally grounded, either in primary legislation or specific regulatory instruments, to ensure stability and predictability for all stakeholders.
2. **Before considering network expansion, however, regulators should prioritize frameworks that encourage optimization of existing infrastructure**. Grid Enhancing Technologies (GETs) and other

measures remain underutilized despite their potential to create "virtual" capacity and mitigate or postpone the need for new development. **Regulatory frameworks should explicitly include incentives for technologies that improve the efficiency of existing assets**, such as dynamic line rating, advanced power flow control, and topology optimization systems. The Georgian case study (paragraph 5.3) provides an instructive example, with its structured assessment system that explicitly values efficiency improvements as a key evaluation criterion for investment projects.

3. **When new infrastructure is necessary, the concept of "anticipatory investments" - which proactively address expected developments beyond immediate needs - is gaining importance** across jurisdictions. However regulatory approaches to such investments vary significantly, with substantial differences in how future needs are forecast and incorporated into planning frameworks. Most jurisdictions focus on relatively short planning horizons (3-10 years), with limited application of multiple scenario analysis. Regulators should **encourage the development of more sophisticated scenario planning approaches that consider multiple possible futures**, particularly for investments with long lifespans. In general, a strategy of more integrated cross-sectoral planning is auspicated.

4. **The survey clearly demonstrates the value of standardized grid plan templates with consistent minimum requirements**. Ten out of thirteen surveyed jurisdictions have implemented formal templates for transmission system operators, with similar standardization emerging for distribution system plans. **These templates should encompass system needs assessment, current state analysis, scenario development, planning assumptions, project categorization, and implementation frameworks**. These templates are more typical at transmission level than at distribution level; but the relevance of distribution network development for the energy transition implies that regulators should approach also the distribution planning, adapting it to local conditions.

5. **Cost-Benefit Analysis (CBA) frameworks remain at varying stages of development across the surveyed jurisdictions**, with significant differences in methodologies, benefits considered, and threshold application. Only four jurisdictions reported having clearly defined CBA methodologies, with others relying on ad hoc approaches or limited to specific project categories. This suggests **substantial room for improvement in CBA implementation**. The survey results support the recommendation for proportionate CBA frameworks with appropriate thresholds based on system size and project significance. Georgia's approach, with differentiated thresholds for transmission (approximately €1.7M) and distribution (approximately €0.33M) projects, provides a potential model for scaled requirements. These frameworks should include standardized methodologies for quantifying multiple benefit categories, with progressive expansion to incorporate environmental and social benefits over time.

6. **The treatment of investments in regulatory tariffs shows significant variation across jurisdictions, with approaches ranging from recognition at approval to recognition only upon commissioning**. Five jurisdictions recognize investments at commissioning, four at the moment of approval, and two during the construction period. Each approach allocates risk differently between system operators and consumers. The North Macedonian case study demonstrates how early recognition can serve as an incentive for investment, though with appropriate mechanisms for ex-post adjustment if implementation targets are not met. Regulators should consider how their approach to tariff treatment aligns with broader objectives for system development and risk allocation, potentially using differentiated approaches based on project categories.

7. **The survey reveals that advanced incentive mechanisms for timeliness and efficiency remain limited**, with only few jurisdictions implementing balanced bonus/penalty systems for timely execution. **Oman's Project Delivery Incentive scheme offers a particularly sophisticated approach, with staged penalties for delays beyond reasonable deadbands and clear provisions**

for legitimate delays. For efficiency incentives, approaches range from standard cost benchmarking in Austria to unit cost approaches in Türkiye. Regulators should consider developing balanced incentive mechanisms that incorporate reasonable deadbands for implementation timelines, establish clear reference costs for efficiency assessment, link rewards and penalties to measurable performance metrics, and consider both project-specific and system-wide benefits. **The French case study demonstrates how these principles can be effectively implemented, with its target milestones for high-priority projects and tiered penalty system for delays**.

8. **Finally, monitoring frameworks show substantial variation, with eight out of thirteen jurisdictions having established formal monitoring systems. These systems differ in inspection responsibility (regulator-led versus self-auditing) and performance assessment criteria**. The Rhode Island case study provides an instructive example of a comprehensive monitoring approach, with quarterly reporting requirements, regular reconciliation filings, and performance metrics tracking. Regulators should implement robust monitoring frameworks with clear amendment thresholds and procedures, comprehensive assessment criteria for technical and economic performance, and regular reporting requirements that balance administrative burden with accountability needs.

As demonstrated by the survey results and case studies, there is no one-size-fits-all approach to regulatory frameworks for grid investment planning and execution. Different jurisdictions face varying challenges related to system development, institutional capacity, and policy objectives. However, the convergence toward more structured assessment, broader benefit consideration, and outcome-based incentives represents a promising direction for enabling the necessary grid transformation while protecting consumer interests. By learning from each other's experiences and adapting successful approaches to local conditions, regulators can play a crucial role in facilitating the substantial grid investments required for the energy transition.

Grid Optimization	Prioritize efficient use of existing infrastructure through Grid Enhancing Technologies (GETs) and other measures before expanding networks
Standardized Assessment	Implement structured templates for grid plans with clear minimum requirements for both TSOs and DSOs
Cost-Benefit Analysis	Develop proportionate CBA frameworks with appropriate thresholds and standardized methodologies for multiple benefit categories
Scenario Planning	Enhance long-term planning with multiple scenarios to address fundamental uncertainty and cross-sectoral integration
Stakeholder Engagement	Strengthen consultation processes with adequate duration (3-6 months) and multiple engagement methods
Investment Recognition	Design tariff treatment approaches that balance risk allocation while incentivizing timely implementation
Execution Incentives	Implement balanced mechanisms with reasonable deadbands for timelines and clear reference costs for efficiency
Monitoring Systems	Establish comprehensive frameworks with clear amendment thresholds and regular reporting requirements

Table 16. Recommendations for Grid Investment Planning and Execution Regulatory Frameworks

ANNEX: Differences Between Electricity and Gas Regulations

Overview of Electricity vs. Gas Regulatory Frameworks

The survey results reveal interesting patterns in how countries regulate electricity and natural gas infrastructure investments. Most countries apply similar regulatory approaches to both sectors, though with some notable variations in specific areas. The following tables apply to 12 respondents because for one regulator – SERA, Saudi Arabia – natural gas regulation is out of its mandate.

Country	Overall Similarity	Notable Differences
Albania	High	No significant differences reported
Armenia	High	No significant differences reported
Austria	High	Different incentives for timeliness
Georgia	High	No significant differences reported
Hungary	Medium	Different stakeholder engagement processes
Latvia	High	Different CBA approaches (implemented in gas, planned for electricity)
Lithuania	High	No significant differences reported
Moldova	High	No significant differences reported
N. Macedonia	High	No significant differences reported
Oman	Medium	Different approaches to incentives for investments
Romania	Medium	Different incentive mechanisms
Türkiye	High	Similar process with slight variations

Table A.1: General Similarity Between Electricity and Gas Regulatory Frameworks

Detailed Analysis by Regulatory Area

1. Grid Investment Evaluation Process

Almost all surveyed countries use similar formal processes for evaluation of electricity and gas grid investments. Most respondents indicated that the same regulations and evaluation criteria apply to both sectors.

In countries with established energy regulatory frameworks, the evaluation processes for electricity and gas infrastructure investments tend to be harmonized, likely to ensure regulatory consistency across the energy sector.

Country	Same Process for Gas?	Comments
Albania	Yes	Same approval process applies for both sectors
Armenia	Yes	No differences reported
Austria	Yes	No differences reported
Georgia	Yes	Exactly the same rules and procedures
Hungary	Yes	No differences reported
Latvia	Yes	Similar process with no major differences
Lithuania	Yes	Same regulation applies
Moldova	Yes	No differences reported
N. Macedonia	Yes	Same process
Oman	Yes	Same process
Romania	Yes	"Yes, basically procedure is very same"
Türkiye	Yes	Same approval process applies for both sectors

Table A.2: Similarity Between Electricity and Gas for process of grid plan assessment

2. Cost-Benefit Analysis Methodology

Most countries apply similar CBA methodologies for both electricity and gas, though Latvia stands out with a more developed CBA framework for gas.

Country	Similar CBA for Gas?	Comments
Albania	Yes	No differences
Armenia	Yes	No differences
Austria	Yes	Same rules and procedures
Georgia	No	CBA framework was introduced for gas in 2024; planned for electricity in 2025
Hungary	Yes	No differences
Latvia	No	CBA developed for gas sector; in progress for electricity
Lithuania	Yes	No differences
Moldova	Yes	No differences
N. Macedonia	Yes	No differences
Oman	Yes	No differences
Romania	Yes	No differences
Türkiye	Yes	No differences

Table A.3: Similarity Between Electricity and Gas for cost-benefit analysis

3. Scenarios and Uncertainty Treatment

Most countries develop scenarios for electricity and gas separately, with limited coordination between the two sectors.

Country	Joint Electricity-Gas Scenarios?	Comments
Albania	No	Separate scenario development
Armenia	N/A	Not applicable
Austria	No	No joint scenarios
Georgia	No	Separate scenario development
Hungary	No	No joint scenario
Latvia	Partially	"Not jointly, but linked in context of national energy independence strategy"
Lithuania	No	Separate scenario development
Moldova	No	"No specific analysis of complementarity"
N. Macedonia	Partially	"No, except for gas allocation"
Oman	No	Depends on the nature of the project
Romania	Yes	"Yes, basically procedure is very same"
Türkiye	No	Separate scenario development

Table A.4: Similarity Between Electricity and Gas for cost-benefit analysis

4. Stakeholder Engagement

Stakeholder engagement processes are largely similar for electricity and gas across most countries.

Country	Similar Engagement?	Comments
Albania	Yes	No differences
Armenia	Yes	No differences
Austria	Yes	No differences
Georgia	Yes	No differences
Hungary	Yes	Slightly different stakeholder enaggement process
Latvia	Yes	No differences
Lithuania	Yes	No differences
Moldova	Yes	No differences
N. Macedonia	No	"The gas stakeholder goes through various panels of stakeholders"
Oman	Yes	No differences
Romania	Yes	No differences
Türkiye	Yes	No differences

Table A.5: Similarity Between Electricity and Gas for stakeholder engagement

5. Financial Planning and Tariff Treatment

All countries use similar regulatory mechanisms for financial planning and tariff treatment across both sectors, electricity and gas (“no differences” reported in 12 out of 12 respondents).

6. Incentives for Timeliness

This area shows more variation, with several countries applying different incentive mechanisms between electricity and gas sectors.

Country	Similar Incentives?	Comments
Albania	No	"No incentives are applied in the gas sector"
Armenia	Yes	No differences
Austria	No	"Other focus" for gas investments (details not specified)
Georgia	Yes	No differences
Hungary	Yes	No differences
Latvia	Yes	No differences
Lithuania	Yes	No differences
Moldova	Yes	No differences
N. Macedonia	Yes	No differences
Oman	No	No incentives for gas, potentially to be introduced in next price control period
Romania	Yes	No differences
Türkiye	Yes	No differences

Table A.6: Similarity Between Electricity and Gas for incentives for timeliness

7. Incentives for Efficiency (Q8.6, 8.6.1)

More variation is seen in efficiency incentives, with several countries applying different approaches between sectors.

Country	Similar Incentives?	Comments
Albania	No	"No Incentives are applied in the gas sector"
Armenia	Yes	No differences
Austria	Yes	No differences
Georgia	Yes	No differences
Hungary	Yes	No differences
Latvia	Yes	No differences
Lithuania	Yes	No differences
Moldova	No	No specific differences noted
N. Macedonia	No	No incentives for gas investments
Oman	No	No difference
Romania	No	"No Incentives are applied in the gas sector"
Türkiye	Yes	No differences

Table A.7: Similarity Between Electricity and Gas for incentives for efficiency

8. Monitoring Procedures

Most countries apply similar monitoring approaches across both sectors, with Türkiye being a notable exception.

Country	Similar Monitoring?	Comments
Albania	Yes	No differences
Armenia	Yes	No differences
Austria	Yes	No differences
Georgia	Yes	No differences
Hungary	Yes	No differences
Latvia	Yes	No differences
Lithuania	Yes	No differences
Moldova	Yes	No differences
N. Macedonia	Yes	No differences
Oman	Yes	No differences
Romania	Yes	No differences
Türkiye	No	"In gas sector inspections for DSOs are carried out by independent audit companies authorized by the regulator"

Table A.7: Similarity Between Electricity and Gas for incentives for efficiency

KEY INSIGHTS AND PATTERNS

1. **High Overall Alignment**: Most countries apply similar regulatory frameworks to electricity and gas grid investments, suggesting a trend toward regulatory harmonization across energy sectors.
2. **Emerging Differences in Advanced Regulatory Areas**: The greatest differences appear in more sophisticated regulatory mechanisms like incentives for timeliness and efficiency, suggesting these areas may be at different stages of development between sectors.
3. **Limited Integration of Scenario Planning**: Despite similar regulatory frameworks, most countries develop scenarios for electricity and gas separately, with limited joint consideration of cross-sectoral interdependencies.
4. **Audit and Verification Variations**: Where differences exist in monitoring procedures, they often relate to who performs the verification (regulator vs. independent auditors), rather than the substance of the monitoring approach.
5. **Different Maturity Stages**: In some cases (e.g., Latvia's CBA framework), the differences reflect different stages of implementation, with one sector serving as a testing ground before approaches are applied to the other.

CONCLUSION

The regulatory treatment of electricity and gas grid investments shows substantial similarities across most surveyed countries, reflecting a trend towards harmonized approaches to energy infrastructure regulation. However, differences emerge in more advanced regulatory areas and in the integration of cross-sectoral planning. These differences likely reflect the relative maturity of the sectors, their different technical characteristics, and the evolution of regulatory frameworks over time.